BEFORE THE

ILLINOIS COMMERCE COMMISSION

IN THE MATTER OF:	)
	)
ELECTRIC POLICY MEETING	)
	)
FERC'S STANDARD MARKET DESIGN HEARING	)

Chicago, Illinois

October 15, 2002

Met, pursuant to notice at 9:30 o'clock a.m.

BEFORE:

THE COMMISSION EN BANC

APPEARANCES:

MR. CRAIG GLAZER, Vice President,
Governmental Policy
PJM Interconnection, LLC.

MR. BILL MALCOLM, Manager,
State Regulatory Affairs
MISO, Inc.

MR. DAVID WHITELEY, Senior Vice President,
Ameren Services Company

MR. BOB FERLMANN, Director,
Energy Supply, and
MS. DEBBIE LANCASTER, Regulatory
Liaison, Electric Supply
CILCO

APPEARANCES (continued):

MR. GREG SCHAEFER, Regulatory Manager,
Wholesale Trading
MidAmerican Energy Company

MR. STEVEN T. NAUMANN, Vice President,
Transmission Services
ComEd

MR. SHAWN SCHUKAR, Vice President,
Energy Supply Management
Illinois Power

MS. REGINA M. CARRADO, Regulatory Specialist,
Exelon Generation Company

MS. REEM FAHEY, Director,
Market Policy
Edison Mission Energy/Midwest
Generation

MS. JULIE HEXTELL, Counsel
Constellation NewEnegy, Inc.

MR. VITO STAGLIANO, Vice President,
Transmission Strategy
Calpine Corp.

MS. PATTY HARRELL, Manager of Asset.
Commercialization
Reliant Energy

MR. JIM DAUPHINAIS
Brubaker & Associates, Inc.
Illinois Industrial Energy Consumers (IIEC)

MR. RON EARL, General Manager & CEO
Illinois Municipal Electric Agency (IMEA)

APPEARANCES (continued):

MR. JACOB WILLIAMS, Vice President
Generation Development
Peabody Energy

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Patricia Wesley, CSR
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I N D E X

COMMISSIONER HARVILL: We are going to go on the record. Good morning. This is a Special Open Meeting of the Illinois Commerce Commission convened as an Electric Policy Meeting to discuss the Federal Energy Regulatory Commission's recent proposal to create a standard market design to standardize wholesale energy electric transmission service.

Present today are Chairman Wright, Commissioners Kretschmer, Hurley, Squires, and myself, Commissioner Harvill.

We appreciate all those who will present testimony here today as well as all of those in the audience as well.

The Commission has taken something of an unprecedented step of convening this meeting to receive comments from participants in Illinois' restructured energy markets to aid us in preparing our comments to the Federal Energy Regulatory Commission.

As most of you know, the standard market design is a comprehensive rulemaking in excess of 600 pages and our goal is to hear from those parties who actually operate and use the grid, so our comments to the FERC reflect the operational realities of the marketplace.

The comments received today will be considered by the Commission, and I, again, thank our panelists in advance of taking the time to join us.

Also, as we noted in the notice of this meeting, parties are also invited to submit written comments regarding SMD to the Commission and you can do so by sending them to my assistant, Katie Papadimitriu, where they will be placed on-line along with all the other comments.

As you all know, however, the Commission will not be bound by any of the comments that we hear, and certainly what we are seeking to do here today is just be able to formulate the best possible comments as we possibly can when we make those to the FERC.

That being said, the format for today has been divided into four panels. The agenda has been distributed. Everyone should have a copy of that. If you don't, I know there are some available outside the hearing room on the table.

Each panelist will have between 10 and 15 minutes to make an oral presentation. After the panelists speak, the Commissioners will then ask questions.

I should also indicate that today's meeting is being heard in Springfield so that when you speak, please speak directly into the microphone so Springfield can hear what you have to say.

One other note, there is a microphone set up in the audience today. After the presenters make their presentations and the Commissioners ask their questions, if anyone else has a clarifying question for the panelists or have something of value to contribute, we would be happy to hear that understanding that we do have certain time constraints here today.

That being said, we are going to start off today with our first panel, which is Craig Glazer, Vice President of Governmental Policy for PJM Interconnection, and Bill Malcolm, Manager of State Regulatory Affairs for the Midwest ISO.

I think Craig's going to begin things this morning for us. So, Craig, with that, I turn things over to you. You will have about 15 minutes.

5 PRESENTATION

BY

MR. GLAZER:

Great. Great. This on? I guess it is on. Okay. Mr. Chairman, Commissioners, staff, I really appreciate the opportunity to be here. It's always good to be in Chicago, and especially today.

I woke up this morning and this sniper was actually at my local Home Depot store, quite frankly, in my new location in Virginia, so it's a lesson. And when I go to save a few bucks by going to Home Depot, instead of the local hardware store, I'm going to think twice about doing that these days. The lesson I learned is if you are thinking of moving, don't move from your present location. I moved to Virginia and it's caused some interesting developments.

I'm here to spend just a few minutes on just giving you an update, since I was last here, on what's been happening with regard to the implementation of markets in the ComEd and Illinois

Power service territories. I want to spend just a couple minutes on that, but then I'll spend most of the time dealing with the Standard Market Design.

First, and foremost, I want to thank all of you, and I know how difficult that decision was when you were wrestling here -- I remember you were wrestling with the decision of what should you say about the elections of the various companies, and I'm proud to say that you actually -- a lot of good things have happened since then. I know there were skepticisms is this ever going to happen, and a whole lot of good things have happened.

For one, I'm really pleased to announce we have actually assigned an implementation agreement. I can make that implementation agreement available with Com Ed, so we are, in fact, at the point now where we are actually full-scale working to roll out and develop the marketplace that's going to support retail choice in the State of Illinois and get the wholesale market that you all have been looking for.

What's important about the implementation agreement is the age old expression "show me the money". This is where the money's on the line. The companies have made a commitment and we are moving forward on that.

We have a signed agreement. We are looking at December 1 of this year, which is not very far off, beginning the process of having the ISO, in this case, PJM, overseeing the reliability function, overseeing the selling transmission service, having a single non-pancake rate, at least between ourselves and other PJM companies, and, obviously, there's additional work that needs to be done, and we are also having a market monitor for the first time performing oversight functions, so if you have got a concern, there will be somebody independent to turn to.

We are looking for a December rollout date, December '04 rollout date, for the market. That is a very quick time period if you realize all the thousands of things that have to happen between now and then, but we are looking to have a vibrant, competitive wholesale market up and running in the ComEd territory next December. We are starting this December and agreements are fully underway.

One other comment on that, we have been working this thing literally 7 by 24. We have started the process of posting the actual or projected locational marginal prices. They are actually posted on our website and they're actually going to have a briefing available for the Commission the last week of October by phone to sort of take you through that, but they are already posted on our website. They are just projections of what the wholesale prices could be, what the congestion points are by each location, and we are going to get you information out. We're hoping to participate on this call the last week of October to deal with that.

I'm also proud to say -- you said, you know, I don't want to have a lot of dispute between MISO and PJM, two organizations really work well together. We have no daylight between us. We have a reliability plan that we have agreed on. To ensure the reliability, that plan was approved by the MAIN reliability council, the MAC (sic) reliability council there are a couple of naysayers in the ECAR region, just to our east here, and we have got a little problem with the ECAR region, but we are trying to work through that as well.

We are working on some issues that the State of Wisconsin have raised you need to be aware of. With regard to Wisconsin, they're looking for a hold harmless clause. They want compensation to be held harmless and you all obviously have an issue with that in terms of where did the money come from to hold the State of Wisconsin harmless in this process and what does -- exactly what hold harmless mean, so I just want to call to your attention we are working through it. We are problably going to the FERC administrative law judge. I think you all -- you may want to focus on that issue as well. Your counterparts in Wisconsin are looking to be held hold harmless.

When we say "Where does the money come from", I don't get a clear answer from them as to where the money comes from, but I certainly wouldn't want it to come from the people of Illinois.

So all in all, we are also working together on a joint and common market with MISO. We

are looking at an October '04 date for that, so a lot of good things are happening, and we think this was the right decision, that it will be a good decision, and I want to pledge again that I want to be personally available to you.

My colleague, Bryan Little, is here. Brian's somewhere in the back there. We want to be available to you here in the State of Illinois to meet your needs as we go forward.

With that being said, let me cover the Standard Market Design. I'm always amazed. I like to sort of be a student of history a little bit in my spare time and you think about decision-making processes. The Gettysburg Address was, what, 210 words? The Ten Commandments were all put on two tablets.

By contrast, we have the Standard Market Design, which is over a thousand pages of text, and tariffs, and details, and, frankly, some of those details are, in fact, causing rebellion, as I'm sure you see at NARUC's meeting next week some of those details and question how much detail you need and how much you don't is very much up in the air.

Let me cover a couple of issues quickly. I have got a -- there's two handouts I would like to concentrate on, the one marked "Standard Market Design NOPR Comments Presentation to Illinois Commerce Commission," and let me highlight some of the areas we have issues with.

Number one is the governance area, and that's obviously an important one -- we should spend a few minutes on that -- the role of the North American Energy Standards Board, or NAESB. We have got some issues with regard to markets, issues with regard to planning, capacity adequacy, and others.

In fairness though, although there's lots not to like in the SMD, there's a whole lot to like in the Standard Market Design, and, quite frankly, Chairman Kathy Riley of the Maryland Commission -- there was a forum held recently -- she said an interesting thing. She said, you know, there are states that are moving forward, Illinois being one of them, Ohio, Pennsylvania, Maryland.

Are we going to be in the situation

where, because of political pressure, we end up as a least common denominator?

There's good things about standardizing markets, but what elements do you standardize them to? If you standardize them to whatever's politically acceptable throughout the west, and southeast, and the northeast, and the midwest and what do you end up with? I think that's something that we all ought to be concerned with.

That being said, let me go into the details and start with the governance issue. We think at PJM we have a system that works pretty well and the critical test is the test of use. Our state commissions in the PJM region have been very pleased with the governance instruction.

We have an independent board. We have no ties to market participants and we have a voting system that says that the ISO is accountable both to the state commission, to FERC, and to the market participants, to the members. These are people that we skin the game and there needs to be some accountability to them, again, not favoring one group or another.

The FERC model is different. The FERC model says -- it blows hot and cold. On the one hand it says you are accountable to the Federal Energy Commission and no one else, and we have some concerns about that. We think any business -- and we operate the ISO like a business -- any business needs to be accountable to the people that have invested in the state, but the other part of the NOPR it says that the board members are chosen by a nominating committee. There's a sort of select group. There's one or two generators, one or two transmission owners, one or two end users, and they meet as a group and they're suppose to choose the board members. It would be one thing if they nominated the board members, but the way the NOPR is written, it says those people choose board members.

To me, that's sort of a situation like imagine a presidential election. You had party conventions in July and the party conventions met and chose the president. Each one alternated every four years and they just chose. There never was an election in November, you know, that may be great if that's your party, and your guy or man or woman got in.

We don't think that's an appropriate system and the system we have proposed to FERC takes the voting process away from the entirety of the membership and gives it to a select few, and we think that's going to cause more problems and elevate some members over others, some generators over others, some transmission owners. We don't think that that was a good, sound governance or certainly a business-like proposal, so that is one we are going to be commenting on.

There also are proposals to change the -- to change the sectors. We have balance sectors and there's an intention to create new sectors for alternative energy providers, et cetera.

I mean, that's great. Those people need some attention, but you do get into some interesting situations. Where you have got a sector made up of two or three people that can out vote another whole sector, do you, in fact, create its own form of market power by putting all this authority into one group or another? So there's a lot of troubling issues.

FERC has gone into a whole lot of detail over this issue and the commissioner having said this is sort of too much micromanage of the ISO voting process.

Let me go on to cover the issue of the North American Energy Standards Board, and I know you are probably more expert at this than I. Ms. Kretschmer, I believe you have served on the NAESB Advisory Board for many years.

We think there's a real important role to play in NAESB. We think that it can be successful, but, frankly, we don't -- we're a little concern that we don't end up with a standard setting body that trumps (sic) what you may want to see happen in this region, what the ISO board may need to do in a particular region, et cetera.

You have got sort of a strategic situation where we were not able to obtain a vote. The states I think have to dilute their vote, but we as ISO were not able to obtain a vote, so we're advisory to the NAESB process.

We are advised -- we are a group of independent entities who are advising a stakeholder board made up of market participants and we think there may be some real potential shenanigans depending upon what issues they get into.

Let me go to the market issue, and this is one I think deserves some attention, because it has a direct -- an absolute direct impact on the rollout schedule here in the State of Illinois, both for MISO -- I won't speak for MISO, but I think they would concur -- for MISO and to PJM. This is one that hits the consumers right on the nose with regard to the proposal.

There's a lot of good things about what's in there. It calls for an LMP-based system. It calls for financial congestive revenue rights. There's a lot to be liked, but it also calls for a system of hourly markets basically allowing generators to change their bids every hour in real-time -- in a day ahead and in real-time, and there's a couple of problems with that.

Quite frankly, you know, this is all a series of computer outerrhythms that are solved to come up with the least cost reliable dispatch. We do it on a day-ahead basis. The computer runs the outerrhythms and sets forth the dispatch, then in real-time it is changing, correcting that dispatch to reflect, you know, differences of the weather getting warmer, or colder, et cetera.

When you go to an hourly market, you increase -- as opposed to day-ahead market, you increase the number of these calculations a hundred fold, and it does come a point when the computer just does so much. It can just solve so many variables, and, particularly, as we are looking to the rollout a very large marketplace, between MISO and PJM, we are afraid that this insistence on hourly markets will severely delay that schedule.

What was FERC thinking? We talked to FERC. What were they thinking? They took a situation in New York and they said, well, the New York ISO allows generators to change their bids every hour, so that's a great thing, so we are mix-matching, and so let's choose that from the newer ISO, but there's a whole lot of differences.

What they didn't choose is the other half of the equation. There's all kinds of penalties. There's limitations. Reliability limitations and generators can't just willy-nilly actually go off the system, and they didn't choose any of that. They didn't put any of that in. They put half the proposal in. So we have got a system of hourly bidding without all the penalties of reliability restrictions. It's reliability issues when somebody can go up and down a generator every hour.

There are two solutions here. We could go to an hourly bidding system -- but we were planning to say to FERC if you do that, you need all these bells and whistles. You need a lot more ISO oversight over the generators to keep the lights on -- or we can stay with the present system, which allows a lot of flexibility in our system and but does not have an -- does not have these penalties, but it's a day-ahead system. It's not an hourly bidding system.

We took it to our members and they

overwhelmingly said we will stick to what we have got. The PJM system is flexible. It allows generators to plan what their next day's dispatch is going to be and doesn't have all these penalties that New York has, so we took it to them and they said don't go there right now.

The other aspect of this, quite frankly, is gaming. There is a real potential for gaming. If you can change your bid every hour in real-time -- we lock our bids in in the day ahead and just have a limited market for deviations -- a whole lot of gaming can go on. You have a heat wave coming through and suddenly somebody's adjusting all their bids.

We think this is not a wise decision for FERC. Given all the other issues that have been put off, this one is front and center and where it means something to the people of Illinois is that this will delay moving forward in the marketplace. If we have to implement this on day one, maybe we can put this off, maybe we can deal with this in the future, but if we have to implement this on day one with the schedule that I have outlined at the beginning of this talk,

frankly
it goes out the window. We cannot do it, and we think at the end of the day it's better to have the energy market up and running, even if it isn't the perfect -- theoretical perfect energy market, than to put all these limitations in. The same goes with regard to the day-ahead ancillary market. I won't bore you with the details, but it's very much the same issue.

There's a whole lot of other issues. I won't spend a lot of time on them. Market monitoring -- there's a lot of good things in there about market monitoring. That's a whole issue about capacity, which is worth another day, but FERC has put that issue off for further discussion.

Bottom line is what they are proposing with capacity doesn't work in the retail choice state. You can't do it with retail choice. What they're asking for is basically retail suppliers to lock their load in years in advance.

We have a more market-based system. We operate a market in capacity and we think that may be a better solution than this sort of back to the old dire days of planning many years in advance.

Let me at this point close by just indicating again that, number one, we are making some great progress here. You are going to have a market up and running by December of next year. It will be successful. It already has a proven track record. We have done this before and it will be done and we are moving forward on that very well.

We have got some issues with the SMD. I mentioned governance. I mentioned the hourly markets. Those are some things that can get in the way of progress that I think all of us are looking to have to bring real value to the people of Illinois.

With that, I'll close and be happy to take any questions.

COMMISSIONER HARVILL: I think we are going to go on to Bill Malcolm.

PRESENTATION

BY

MR. MALCOLM:

Good morning. My name is Bill Malcolm.

I'm the manager of State Regulatory Affairs for the Midwest ISO. With me today -- and I would like him to stand -- is Doug Taylor, our director of Strategy from the Midwest ISO, and Josh Pinstone (phonetic), Project Architect.

Just quickly going over the handout that's available on the front table, "MISO and Illinois Today", as I'm sure most of you in the room are aware, CILCO is a member of the Midwest ISO and Ameren and MidAmerican will both be operational next year, Ameren with the GridAmerica and MidAmerican with TRANSLink, also the city of Springfield, as I'm sure many of you are aware, is a transmission owning member of the Midwest ISO.

Midwest ISO went operational in February 1 of this year, so we are a relatively new organization. We have a diverse membership base with five-for-profit independent transmission companies under our umbrella, a Canadian utility, Manitoba Hydro, as well as vertically-integrated utilities like Ameren and CILCO, which are here in the room with us today.

Also, as the Commission is well aware, the Illinois Commerce Commission will be the lead Public Service Commission representative on the MISO Advisory Board next year.

MISO tomorrow, as you may know, we are in the process of merging with the Southwest Power Pool of Little Rock, which will bring some southern states to the MISO footprint as well as fill in the gaps in Missouri and Kansas.

Right now we are working on integrating new members like TRANSLink, ITC, and GridAmerica. We are very much involved with PJM in the development of a joint common market, as Craig mentioned, and we have had a two-year stakeholder process developing the use of locational marginal cost price saving to manage congestion.

Upcoming dates -- and the reason I mention this is because my comments today will be somewhat limited. Tomorrow is our monthly MISO Advisory Committee meeting and at that meeting on the agenda we will be going over with our stakeholders some of our draft comments on this Standard Market

Design; therefore, today I have to be somewhat general since really tomorrow is the first time we have had an opportunity to discuss with our stakeholders our comments.

Some of the key dates coming up for the Midwest ISO include February of next year when we expect to have GridAmerica operational and a full member of ISO -- that brings the Ameren Companies into the MISO footprint, and September of next year when the TRANSLink ITC becomes operational. That brings MidAmerican utility in under the footprint.

We hope to have a real-time market up and running December of next year and, as Craig mentioned, the joint and common market begins operation in 2004.

Just real briefly, I wanted to go over some of our SMD comments in a little bit more detail. Basically, the Standard Market Design proposal, as Reem Fahey and others can attest, is consistent with the two-year stakeholder process that we have been involved in in our congestion management working group to move away from using what's known as transmission line release to manage congestion and implement, like

PJM has, a locational margainal cost pricing congestion management system. This requires the creation of spot markets for energy and as well as an imbalance service, so basically we see the SMD as consistent with what the Midwest ISO is doing or planning to do, and that perhaps is our most important comment.

We do agree with FERC that it will permit creation of competitive wholesale markets. Specific concerns, there's a been a lot of talk at the state commissions, as I'm sure the Commission's aware, about the regional state advisory committee's idea what the FERC meant by that, and I see they will be taking that up at in the NARUC annual meeting next month here in Chicago.

As you know, the Midwest ISO is a very open stakeholder-driven process. We have a very good relation we think with many, or if not all, of the state commissions, so we look forward to working with the states on whatever they and the FERC decide is the best format to use, and I know Michigan PSC is pushing the multistate initially proposal, so it's very fluid.

Just turning briefly to the timetable for implementation of the SMD, Craig touched on a number of the issues, and we have similar issues to PJM on this. Very tentatively, we were planning to have the market operational by December 20, '03, but services wouldn't be operational due to software and other issues until late 2004, so the FERC timetable, which has everything going in by the end of 2003 under at least the initial proposed draft, looks somewhat ambitious.

Similarly, for transmission planning, we will be issuing a draft regional transmission plan for the Midwest ISO footprint at the end of this year; however, if we would have to do a transmission plan for SPP, and PJM, and MISO, the combined footprint, for example, within six months of the final NOPR order, that might be more of a herculean task, so we want to take a close look at that timetable issue as well.

Congestion revenue rights, the number of stakeholders, I know a lot of people in the room have a lot of concerns on some of the details of this.

We are having a transmission rights task force working group meeting to talk about our views, for example, whether the move to an auction-based system after the transition period should be mandatory is one of the issues or should it remain voluntary.

Market monitoring, I know the Commission staff in Springfield this is a topic dear and near to their hearts. We certainly support the change to having the market monitor report directly to the board and to regulators.

As you may not be aware, Chairman Wright, we are currently not dispatching generations, so the market monitoring role is a little bit different than would apply in more on a prospective basis, but we certainly support the SMD's proposal in this regard, especially including the mitigation of market power using safety net bid caps to avoid a California-type experience.

Long-term resource adequacy, really this is going to be the subject of a detailed FERC workshop later this year, so we'll postpone comments to the January filing date for comments, similarly for the state participation, I touched on that.

Finally, Craig talked a lot about the governance issue, some of the concerns of that PJM has. I think it would be fair to say that the Midwest ISO shares with PJM in their concerns on the governance issue. We want to take a close look at the rules governing the selection of a board and would favor perhaps this being for a new applicant or for board seats that would be up in election for 2003.

Basically, we feel we have an independent board already in place and that meets the FERC's independence test, though we are not sure of the benefits of imposing a new set of regulations, and also we have an order from the FERC on merging with the Southwest Power Pool and combining our boards, so we feel this order should probably take precedence over a more generic order.

And with that, I would like to open it up for any questions that you have. Thank you very much.

COMMISSIONER HARVILL: Thank you, Bill.

Are there questions from the Commissioners?

Commissioner Kretschmer?

COMMISSIONER KRETSCHMER: I have one for Mr. Glazer. You mentioned Wisconsin. My ears always pick up the name Wisconsin.

COMMISSIONER HARVILL: Why is that?

COMMISSIONER KRETSCHMER: Because for years they manage to have lower electric prices than we have even though they were using ComEd's electricity, so I'm serious. What do they want now? You said hold harmless. Can you give me -- I have not heard of this.

MR. GLAZER: A great question, Commissioner Kretschmer. They protested the Wisconsin Commission -- the Wisconsin companies protested the decision of the ComEd to join PJM, and FERC responded to that by saying that the Wisconsin transmission owners and the state for that matter, as well as Michigan, should be "held hold harmless" from Commonwealth Edison's decision. They didn't give any more details on what hold harmless means.

The language that was used talks about it in terms of reliability, and there's no question, and we agree, from a reliability perspective, it shouldn't be an adverse impact to Wisconsin from ComEd's decision and both us and MISO are committed to make sure that doesn't happen.

Here's the rub. What the Wisconsin folks are saying we want more than that. We want compensation as if ComEd was a member of MISO, okay, and we want to be compensated for that, including all the revenue distribution, all the bells and whistles that would have come from that.

Well, ComEd made a different decision and, no, the people of Wisconsin should not be hurt by that, but this was a voluntary system, so the question is, you know, should they get payments for a decision they didn't make, that ComEd did make, and drived income from, which is a real significant issue? Where is the money coming from?

We asked the Wisconsin folks where does the money come from to hold them harmless? Does it comes from ComEd's shareholders? Does it come from ComEd's ratepayers? And they said we don't care where the money comes from. We just want the money.

There's a question of what money? I mean, are we going back to what the system ideally should have been between Wisconsin and Illinois in trying to compensate Wisconsin for that -- well, it never was that system -- or are we just trying to deal with the incremental impacts, reliability mostly, but even some commercial associated with the decision to join PJM? That's the issue.

COMMISSIONER KRETSCHMER: Why am I not surprised. For years and years FERC set the charges for the transmission and for years and years they didn't cover the actual cost, and so for years and years ComEd and Illinois ratepayers were subsidizing ratepayers in Wisconsin. I'm not surprised, but I certainly would expect in the future Wisconsin is responsible for their own system.

They didn't bother building generation or interconnection. They didn't bother building generation and now they want all of us to be responsible for their errors. I think we need to take a very close look at that, and I hope MISO and PJM are looking at that and will respond properly.

MR. GLAZER: We are going to do that, Commissioner, but it's really important that the Illinois Commission will be at the table.

COMMISSIONER KRETSCHMER: We sure will.

COMMISSIONER HARVILL: Commissioner Hurley.

COMMISSIONER HURLEY: You can argue that they knew what they were doing.

COMMISSIONER KRETSCHMER: Until now when the chips are down and now they're being called to fix their system.

COMMISSIONER HARVILL: Craig, would you spend a little time and talk about the SMD as it relates to PJM. I know -- from what I know about PJM and from what I read in the proposed rule, a significant portion of that rule is lifted from the PJM blueprint.

Many parties have talked about the aggressive nature of the rule and that the FERC is moving too quickly. From an organization from which the FERC actually took a lot of what they want to do, are the timetables too quick?

You have a lot of this stuff already in place. So if it's difficult for you to put this stuff in place by the time line the FERC has suggested, I would, in turn, estimate that it would be difficult for others to meet those deadlines as well.

MR. GLAZER: Commissioner, I think you raised a really good point. This is very much in contention and you will hear a lot about this in the NARUC meeting for sure.

Here's the dilemma. You need to have -- we need to move forward in this country with a Standardized Market Design, just like when you go to the grocery store and there's those little UPC labels, they're standardized from grocery store to grocery store. You need -- just like when you put a plug in a wall, you need to be able to use that plug, whether you are in Wisconsin, or Illinois, or the State of Washington, so a certain amount of standardization is absolutely essential, especially, quite frankly, in the State of Illinois here given the configuration, the choices of the companies, and the fact that you are part of an interconnected grid. We're all together in this, so a certain amount of standardization.

That being said, you are absolutely right. One of the problems with the SMD is it puts everything on the table and seemingly all at once.

Here's the rub. The question is this. I'm sure the people at the state commission will argue and NARUC will argue regional differences. Regional differences are important, but regional differences can also be a code word for doing nothing, and that's the problem.

Personally we would much rather see a phased approach, and we are thinking about putting this in our comments, what things need to be done fairly quickly and what things can be put off, and those things that need to be done, we need to move forward in this country on those. Other things can be put on the back burner, and then there may be a third set of things which it doesn't matter if it's in Alabama or Illinois.

FERC didn't make those decisions. I think they will. The problem I'm worried frankly if NARUC, for example, comes out and just says regional differences because that could be just a code word for just keeping the old monopoly system.

COMMISSIONER HARVILL: Bill, do you have any thoughts about that?

MR. MALCOLM: Well, I guess we support a phased approach as well, especially for some of the things where the software wasn't ready or looked too aggressive. No, I'm generally in agreement.

COMMISSIONER KRETSCHMER: I'll comment on that. Some of my fellow commissioners from Florida, from Oregon, from Washington, from Kentucky would point out that their electric rates are lower than ours and they choose not to become involved, and, you know, if I were a commissioner in those states, I would agree, so we can talk about half standardization, but I think the standardization reflects the area from which you come.

A standardization, as far as what NAESB is doing, as far as getting wording, phrasing, contracts standardized, that's one thing, but I don't think that

the FERC has the authority, the legal authority to order a state to enter into a MISO, or ISO, or anything else you want to talk about. They're going to run into the governors, and the governors are having no part, so I think you are being a bit optimistic, Craig, that the FERC's going to take on the governors of this country.

MR. GLAZER: It wasn't talking politically, but more so what should happen.

COMMISSIONER KRETSCHMER: You have got to be political. You have seen what the governors are saying, so they're not about to change their mind, so you better plan on doing this on a long phase, maybe 50 years or so.

(Laughter.)

COMMISSIONER HARVILL: I'll leave that.

COMMISSIONER HURLEY: Think of the telecommunications industry and how long that's taken, but FERC doesn't order the state. FERC orders the utilities on which it has jurisdiction.

COMMISSIONER KRETSCHMER: They may order the utilities, but I think the governors have something to say.

COMMISSIONER HURLEY: Sure, from a political standpoint, but that's not what Craig is espousing.

MR. GLAZER: Right.

COMMISSIONER KRETSCHMER: That's the governors.

MR. GLAZER: The other thing, if I may comment on the other part of this, is I think frankly that my former colleagues in the low cost states, I think it gets missed in a little bit of the discussion, FERC has jurisdiction over transmission. The big dollars are in generation.

COMMISSIONER KRETSCHMER: Don't even make that argment. Don't even make that argument. We are talking about the percentage basis and the percentage basis that I have seen for the transmissions are very, very substantial. That's not an argument that I think can be made successfully.

MR. GLAZER: But my only point here was that the FERC did not trump (sic) the ability of the low cost states to have jurisdiction to make decisions about the portfolio of generation that their individual companies have.

If the State of Kentucky wants to put bundles and the State of Kentucky wants to tell

Louisville Gas and Electric don't let any electron leave the state and solely dedicate your least cost generation to your native load customers, there is nothing in the SMD that can change that. That is a generation portfolio decision that the state still has jurisdiction.

COMMISSIONER KRETSCHMER: You are talking about Texas. Texas is the only one that's not interconnected.

MR. GLAZER: But the state still has authority through the fuel adjustment clause in those states. That's where it comes in. If they, in fact, do that, they can be penalized.

COMMISSIONER KRETSCHMER: But the electric flows like water. It will go through Kentucky, the line -- the switch, and it will go through anybody. This is not as simple as it sounds, and you know that.

MR. GLAZER: I agree.

MR. MALCOM: Can I make a quick comment. We think that with PJM and MISO being two RTOs here in the midwest and in Illinois, that certainly makes a lot of sense to have a common set of market rules, which the

SMD has, and the joint and common market of PJM, Southwest Power, and MISO is in 26 states, so it speaks for itself.

COMMISSIONER HARVILL: Are there other questions or comments from the Commissioners?

COMMISSIONER HURLEY: I wanted to go back to something briefly Commissioner Kretschmer just said when she said it's not as simple as it sounds. It's not simple at all. I have always struggled with it.

COMMISSIONER HARVILL: Clarifying questions or comments from the audience?

(No response.)

I see none. We are actually ahead of schedule, so thank you both. We'll assemble the next panel. We will begin in a couple of minutes once everybody gets up to the table. We'll go off the record for that.

(Off the record.)

We are going to go ahead and get started if we will take our seats, please. We are going to go back on the record now.

The second panel we have presenting today is comprised of our Illinois utilities companies. With us today are -- I'm going to read the list who's going to be presenting, and the order they will be presenting is Mr. David Whiteley, Senior Vice President of Ameren Services Company; Mr. Bob Ferlmann, Director of Energy Supply and Debbie Lancaster, Regulatory Liaison, Electric Supply for CILCO; Greg Schaefer, Regulatory Manager of Wholesale Trading for MidAmerican Energy Company; Steven T. Naumann, Vice President of Transmission Services for ComEd; and Shawn Schukar, Vice President of Energy Supply Management for Illinois Power.

With that, we are going to turn things over to Mr. Whiteley to begin presentation. With that, the floor is yours.

PRESENTATION

BY

MR. WHITELEY:

Thank you. Commissioners, I want to thank you for the opportunity to share with you our current thoughts regarding the FERC Standard Market Design NOPR and, rather than prepare slides, we have prepared remarks, and frankly we are still in the process of evaluating the impact the NOPR will have on our utility operations, as well as our unregulated operations.

Analyzing and refining the NOPR provides a unique challenge to Ameren due to our diverse operations. As you know, Ameren's vertically-integrated Missouri operations are not exposed to retail customer choice initiatives as we are in Illinois.

Ameren also has unregulated generation and marketing companies, so our comments to the FERC must incorporate all of these perspectives, but my comments today will address the NOPR concerns that we have largely from an Illinois utility perspective.

For those of you that have had the opportunity to read parts or all of the NOPR, I think you'll come to the same conclusion that we have that if the SMD NOPR is implemented in its current form, it will have a dramatic impact on the way utilities provide service to their retail customers.

The NOPR will have a dramatic affect on the wholesale marketplace as well and Ameren is concerned that the FERC may be moving too aggressively by issuing this very complex new market structure in an attempt to standardize wholesale market mechanisms, and there have been substantial FERC initiatives already underway to establish RTOs and ISOs and those initiatives are progressing and show promise to aiding the development of regional markets.

We have to ask the question whether or not it's wise for FERC to again propose a new structure before the newly-recreated RTOs have had a chance to fully develop.

Ameren firmly believes that implementation of the SMD NOPR in its current form will have the impact of providing service to retail customers. The SMD NOPR could have an impact on reliability of service to those customers as well.

The NOPR clearly states that the FERC intends to exercise exclusive jurisdiction over the transmission system, including use by retail customers. The jurisdictional shift, coupled with the implementation of the Standard Market Design, will have a number of cost implications.

First, the SMD will introduce a new element of risk for providing service to retail load and this risk will emerge in the form of potential congestion charges. These charges will be assessed on those transactions that flow across a congested portion of the transmission system, including transactions to serve retail load. To mitigate the cost of congestion charges, load serving entities, including utilities, will have to obtain congestion revenue rights.

The FERC has proposed in the NOPR to allocate congestion revenue rights to utilities based on the historical use of generation facilities and current peak load, and while that may mitigate some of the exposure to congestion charges, it will not mitigate all of the exposure.

For example, no mitigation will exist from the congestion revenue allocation for congestion charges caused by providing service to new loads, nor will allocated congestion revenue rights fully mitigate the utility's exposure to congestion charges if generation is dispatched in a manner that deviates from historical dispatch patterns and this occurs during generation outages, maintenance, or when new capacity is purchased or brought on-line to meet new loads; furthermore, changes in physical power flows on the transmission system can cause congestion on previously uncongested lines for which the utility may not have obtained sufficient congestion revenue rights in order to fully mitigate congestion charges.

Today the vertically-integrated utility is not exposed to any congestion charges for use of its own transmission system to serve its retail load. Unfortunately, at this point in time we have no idea what our exposure to these charges may be or whether these charges can economically be mitigated.

As a result of SMD, utilities will be required to schedule generation to serve their own retail load. Currently utilities do not schedule generation to serve retail load within their respect control areas and the introduction of these scheduling requirements will expose utilities to potential energy imbalance charges when their schedules do not meet their load and today these imbalances are essentially paid back in kind between the control areas. Under SMD, energy imbalances will be paid at spot market prices which could increase the cost to serve retail load.

In addition, the current pricing practices adopted by FERC are a concern to Ameren and, quite frankly, the SMD NOPR does little to allay these concerns. As most of you know, Ameren has one of the lowest cost transmission systems in the country. The Ameren's transmission system is also one of the most highly-interconnected sysems in the country. This means that Ameren can already reach 28 other energy markets to purchase or sell power by paying one transmission wheel (sic).

RTO participation under the SMD tariff will provide the same capability to other entities that may not reside in low cost or highly-interconnected systems; furthermore, if embedded transmission costs under the SMD tariff are recovered by imposing the postage stamp rate on all

loads served off of the transmission system, everyone will pay the same rate for use of the grid, regardless of which transmission zone or service area in which the load resides, and Ameren's retail customers will see a transmission service price increase from today's levels.

Moreover, if a zoning transmission rate is perpetuated under the market design tariff, which would mean that load in the Ameren zone would pay a zonal rate, as well as loads in other zones would pay their local zonal rate, there still would be a potential for cost shifting from generators to load and from loads connected to relatively isolated transmission systems to loads connected to highly-interconnected transmission systems, such as Ameren.

Generally speaking, by eliminating pancake transmission rates under a zonal or postage stamp structure, improper price signals may be sent to load or generators if the transmission system's operational costs, and/or upgrade costs, are not borne by those entities benefiting from the use of the system or causing a need for an upgrade.

The existence and location of RTO seams continues to be an issue that Ameren is closely following. Ameren believes that all transmission-owned entities should be required to participate in an RTO under the same tariff, including municipal and cooperative systems; furthermore, due to retail competition in this state, Ameren is much more concerned with the market barrier seam that has been created by the RTO elections of utilities in Illinois.

For this reason, Ameren has been a strong proponent for developing transmission pricing that would facilitate transactions between the RTO regions without causing transmission costs or revenue shifts from one RTO to the other.

Absent mitigation on the market barrier seam that will exist in this state, retail competition in Illinois, in Ameren's opinion, will be significantly hindered.

In addition to these potential cost issues, the SMD NOPR introduces some reliability concerns to be considered as well. Ameren is encouraged that the NOPR acknowledges the need for maintaining a minimum planning reserve requirement for capacity; unfortunately, the 12 percent minimum planning margin set forth in the NOPR is, in our opinion, too low.

Ameren believes that the planning reserve margins currently established by FERC and its regional reliability organization should be preserved either correctly or through the formation of regional state advisory committees; furthermore, for competition to work effectively at the wholesale or retail level, the same planning reserve margin needs to be imposed on all load-serving entities in a particular market.

Amerend has concerns about the lack of a transparent capacity reserve margin market from which reserves can be purchased. The creation of a robust and transparent market for capacity should be pursued and when implemented should lower the cost of capacity needed to meet the planning reserve requirements; however, a meaningful planning reserve enforcement mechanism is required as well.

Absent a meaningful penalty for failing

to maintain adequate reserves, load-serving entities may be encouraged to avoid the high cost of maintaining the necessary reserves knowing that their exposure is to a lower cost penalty. Allowing load serving entities to avoid maintaining adequate reserves could have a dramatic effect on power prices if capacity becomes scarce as a result.

Another concern Ameren has with the proposed planning reserve requirements set forth in the NOPR is the requirement to maintain planning reserves for a three-year period. This amounts to significant requirements whereif load shifts from one entity to another in that three-year period, and this is especially true in competitive retail states, the load in the area where load has been reduced will effectively be carrying reserves that are no longer required, so this will result in cost shifts from one group of customers to another. This concern is especially present in an open access state like Illinois.

Ameren is encouraged by FERC's acknowledgment of a need for states that have a role in continued input in aspects of the market design operation.

Transmission planning and siting will most certainly be an area where the states will want to continue to have the greatest of input. The key question, of course, is how much control over new projects should the state continue to have.

I believe everybody recognizes there's a significant need for transmission infrastructure improvements if truly liquid -- energy liquid markets are to be developed; consequently, if this is truly the objective, then the process for siting transmission improvements somehow has to be improved.

The SMD NOPR proposes to improve the process by involving the states in the transmission, planning, and expansion process through regional state advisory committees. And while this will provide the states with a better understanding of the regional need for a particular transmission improvement, Ameren questions whether or not this participation alone will make the acquisition to build a line more possible and less controversial.

I believe it will still be extremely difficult for state commissions to support the construction of a new line that benefits load or generation outside of the state when the cost for building such a line is borne by the residents of that state.

Regrettably, the SMD NOPR does not offer any meaningful solutions to the difficult question of who pays for upgrades, especially those upgrades that produce a regional benefit.

Ameren believes that FERC's transmission system upgrade pricing policies need to be altered or they will continue to hinder future transmission expansion even if the states are allowed to participate in the planning process.

We have spent a good deal of time talking about some of the risks that utilities may be exposed to as a result of the SMD implementation. It's also possible that utility customers will receive benefits from SMD.

In theory, once the SMD tariff is implemented and truly robust, liquid energy markets

will become -- operable energy cost savings will occur and the utilities will share in that. Their customers will also share in the benefits of a liquid energy market. After all, one of the primary purposes for instituting the Standard Market Design is to enhance the competitive energy marketplace.

The hope is that the energy savings from enhanced competition will more than offset any increased costs associated with operating under the SMD.

And this concludes my prepared comments. Thank you.

COMMISSIONER HARVILL: Thank you.

Next we'll hear from CILCO.

PRESENTATION

BY

MR. FERLMANN:

Good morning. CILCO also appreciates the opportunity to share our comments, our thoughts, and our concerns this morning.

What I have provided to the Commissioners this morning is the outline of our FERC filing.I want to qualify that in that we are still reviewing the proposed rulemaking. At this point, this is the draft we are working off on.

Given the vast presentations today CILCO's going to focus on the issues that are pretty specific to CILCO.

As a review, CILCO is an integrated utility. We are a member of MISO.   We have RES status with all of the Illinois major territories, primarily ComEd, but we also have retail customers behind Illinois Power and Ameren. We have a three-prong approach to electric supply. We have focused our load behind the CILCO control area, our growing load behind Commonwealth Edison, and then our wholesale activity which attempt to optimize our generation assets.

Our current environment, which have laying out helps support or highlight some of the issues with the Standard Market Design NOPR. Primarily behind CILCO, we have got competitive-priced tariffs which not only incorporate a fixed commodity component, on top of that, as a direct result of Illinois deregulation, many of our customers have entered into competitive contracts with CILCO utility.

As David also mentioned just a few minutes ago, these customers do not have an imbalanced exposure at this time. Right now our transmission is operated by the Midwest ISO. Specific to our retail book-of-business behind Commonwealth Edison, we support our retail contracts in ComEd with market-based supply contracts. The -- our retail book-of-business basically flows specific to the market value of the CTC determinations, which are made periodically by Commonwealth Edison.

Right now there is not a requirement for capacity back or reserves to support CTC customers. The supply package is that it utilize our liquidated damage base by putting reserves and capacity on top of that in many instances would make it -- we would be unable to compete with the PPO.

Both our retail contracts and supporting supply contracts are long-term in nature and, as also mentioned, Commonwealth Edison is in a different ISO than is CILCO, so there are seams issues that we face behind Com Ed that we do not necessarily face behind CILCO. Primarily we are dealing with a through-and-out rate adder and we have experienced imbalanced costs behind Commonwealth Edison.

On the wholesale side, what the seams hurdles have done to our wholesale business is really shift our wholesale transactions from primarily dealing with our neighbors, the other Illinois utilities, to now dealing with other MISO members, which was probably the original intent, but we, in essence, have shifted a lot of transactions that were Illinois-based to Synergy (phonetic) and other non-Illinois utilities.

There is an another issue that has not been mentioned yet is we do struggle on a daily basis with the difference between transfer capability that is reported via the MISO analyzer versus the transfer capability that we actually pull up on the Oasis System to the utilities and that variance is something that we need to contend with.

Moving into the SMD NOPR, I think everybody's familiar with the objective at this point.

I will try to raise or I will raise questions and concerns specific to CILCO, few resolutions at this time, but CILCO will continue to work with the Commission to develop beneficial positions to Illinois customers.

The NOPR incorporated eight primary strategic components. I'm going to address just several of those this morning.

I mentioned the native load customer risk under SMD and the through-and-out adder, which the SMD attempts to address is really a cost shift from the through-and-out adder rate will now be incorporated more or less into the access charge. The access charge is at this point recommended to be entirely the responsibility of the load-serving entity. This will be a cost that will be directly passed onto native load customers.

CILCO, specifically native (sic) load in our control area, has frozen rates right now and that's an economic issue that we need to deal with.

We are very supportive of the flexibility and some of the optionality that's been expressed.

The Network Access Service does provide the ability to change receipt and delivery points and that is a definite plus.

We have concerns on again the costs that are going to be borne by utilities specific to the required metering devices. The Schedule 10 MISO administration adder will vary soon incorporate significant software expenses. That is another cost that customers are either directly or down the road going to have to bear.

Our concern with the independent transmission providers is that basically they might be asked to take on too many roles. In addition to transmission and ancillary services, administration and operation, the NOPR requires them to take on the real-time, next-day, and even voluntary mid-to long-term energy commodity markets. They are also taking on security coordination. We have a segregation concern and again just too much to soon.

In regard to resource adequacy, especially with the retail focus of Central Illinois Light Company, a resource adequacy time frame that is tied to the ability to bring generation on-line does not match up with the ability of retail customers to shift suppliers very quickly, and we've seen our book of business behind Commonwealth Edison grow from zero to 500 megawatts in less than two years.

Similarly, while no customer has left the CILCO system yet, there is definite concerns that, you know, one or two large industrials could significantly impact the load of CILCO and we might, in essence, be contracting for capacity that is not needed.

The Commission, while I think their initiatives have been very good to date, they have not necessarily been great. In the real world, FERC's vision hasn't played out entirely as they may have intended. Eight eighty-eight or 2000 did not do exactly what was intended and we do have some concerns that SMD is not going to play out exactly as it is in writing.

Another concern that hasn't been yet mentioned this morning, but I wouldn't be surprised if other people addressed it, is one of the biggest changes in the industry, aside with the change in liquidity, is the growing concern specific to credit.

In reading through the order, CILCO is not comfortable at this point who's going to take or assume credit risk in today's environment and credit already is and become an even greater barrier to entry and hindrance to retail competition.

Specific to Locational Marginal Pricing, the CRRs were at this point unconvinced. We support the direction. We are unconvinced that Location Marginal Pricing promotes price certainty at this point.

Again, the bulk of our customers definitely behind Commonwealth Edison and significantly behind Central Illinois Light Company request and receive fixed price supply contracts. The inability to incorporate the costs associated with variable location marginal pricing and the cost revenue or the CRR revenue in cost is a concern that we think if companies can't come into Illinois and hedge this unknown expense, it's going to be another hinderance to retail development.

In conclusion, you know, we do -- we

commend the FERC for its attempts to address the current shortcomings in the industry, but we do caution the FERC to maintain a balance between regulation and natural market forces. We encourage the FERC to address transmission issues.

While there is, in our view, an aggressive time-line attached to the SMD, even a two-year time frame is significant for some of the issues that we are now facing in Illinois, primarily with the seams issue.

We encourage FERC to continue to provide flexibility and optional provisions where possible. We encourage the FERC to not ignore state deregulation. Illinois is different than many of our neighboring states, and what is standardized for a regulated state may not work perfectly for a deregulated state.

We also feel it's important for all stakeholders to be involved in via comments to the FERC, and CILCO will definitely attempt to coordinate its efforts with the Commission, and with that CILCO is also interested in what the Commission's position is. And with that, I will close.

COMMISSIONER HARVILL: Thank you very much. We'll move onto MidAmerican Energy, Mr. Schaefer.

PRESENTATION

BY

MR. SCHAEFER:

Thank you. Like everyone else, we appreciate the chance to be here today and also appreciate the Commission's interest in the topic that FERC has laid before us.

I will also say that a number of comments we are making today are part of an ongoing review with no doubt we will come up with some more before we finally file comments in November and again in January and some of these comments may be altered before they reach their final state.

In general, I have given you a number of written comments. I won't read those aloud to you, but I will hit a few high points this morning.

If I could just give an overview of where we are at with the NOPR, we feel that it is a step forth and a step forward in a more competitive market.

We think that it's a positive step forward and we think it will bring about better competition.

We agree that the current regulatory system we are operating under does create a potential for discrimination and we think that the NOPR lays out a system for independent transmission operation and also a standard market design that would limit the potential for discrimination.

We also think that the NOPR will assist in working towards seamless transmission borders and also help build the infrastructure that we need.

MidAmerican has long sought to encourage regional planning. We have been involved with MAPP, and TRANSLink, and now with the Midwest ISO, and we think that the NOPR will support that regional planning.

We also anticipate that our involvement in TRANSLink and also Midwest ISO will meet the FERC's standard for operation of our transmission system by an independent entity.

I'll label a number of concerns in the next few minutes, but I don't want those to overshadow the general support we have got for the NOPR or the fact we do think that it will encourage transmission to be built and also encourage more seamless markets.

We endorse the NOPR concept of independent -- independent operation of the transmission system. Even though we support that, we don't think that the market operator has to necesssarily encompass all of the responsibilities that the NOPR lays out for it, and I think CILCO hit on some of the same ideas and we also feel there are some duties assigned to the independent transmission provider that would not necessarily have to lie there.

The issue of transmission pricing is important in the NOPR and, as we read the NOPR, we don't think it lays out a definite method of transmission pricing. It does ask a lot of good questions. In that regard, it seemed like more a notice of inquiry than finding a NOPR.

Let me talk a bit about embedded costs. It's not clear in our minds just where the NOPR sees the end-state. It seems to point towards the license plate model, although it does ask a lot of questions about alternatives.

We think there are problems with the license plate model related to the cost shifting and we would support more of a combination highway/zonal rate that's consistent with our involvement in TRANSLink.

We can move onto new transmission next. We are concerned about the NOPR's apparent preference for participant funding. We do think it's an important benefit from transmission to pay for it. We are concerned that an overemphasis on participant funding could further balkanized transmission ownership of the system and could lead to confusion among transmission operators.

Finally, we don't think the NOPR really resolves the issue of pricing between regions. We think that's very important in Illinois where there will be more than one -- more than one ITP represented and where utilities have joined different RTOs.

We do think those utilities are making progress to resolve those seams issues. We definitely think that they need to be resolved.

Let me talk a bit about congestion management and energy markets. Obviously, the NOPR proposes to manage transmission congestion with the system of locational marginal prices. We think that's a better system of market-based system than the current method that results in prorated reductions in transactions.

We don't think that the system laid out in the NOPR is perfect. We think the CRRs do provide at least some financial hedging, but we don't think that's a substitution for an actual construction of transmission, in other words, mitigating congestion charge is no substitute for eliminating the congestion itself.

Obviously, as you heard from several others, and probably will hear throughout the day, the allocation of those CRRs pose special problems for states where retail access exist like Illinois.

The NOPR asks whether CRRs should follow the load as retail customers move from one supplier to the other, and we think that it's extremely important that CRRs do follow the load as it's laid out in the

NOPR.

The NOPR also talks about retail transmission planning, and we support the NOPR's call for a system of regional transmission planning.

MidAmerican has been involved in MAPP in years past and in TRANSLink and MISO. We think the NOPR will make regional transmission planning even more robust than it already is.

We do have some concerns about the mandate -- apparent mandate in the NOPR that any transmission expansion be the subject of the competitive bidding process.

We agree that we should expand the system with the most economic mix of transmission, or generation, or demand response. We think there are a number of situations though where the answer will obviously be one or the other, and we are concerned that we could delay new transmission by getting overly bogged down in a process could be an administrative burden.

Let me talk next about resource adequacy. We agree that the infrastructure does have to be supported through a planning process that provides for resource adequacy that's both cost-effective and also equitable.

In the comments I have given you, we have laid out several principles that are being discussed now within MAPP and that we would support, among those principles that planning reserves should be the responsible -- responsibility, that is, of the individual load-serving entities.

Also, we recognize that the amount of adequate planning reserves may vary from one region to another. We think that all regions should establish a meaningful and enforceable mechanism that permit reserve sharing to meet those planning reserve requirements, and we also think that a long-term planning horizon should be used to evaluate the resource planning.

Retail access we think adds a significant layer of complexity, both resource planning and to load forecasting. We think it's possible to develop a reasonable forecast of total load within an ITP, but it's very difficult to forecast which load-serving entity will actually be serving that load within -- in states having retail access.

We think it would be helpful if the adequacy requirement, like CRRs, would somehow follow the load as customers switch from one supplier to another in states having retail access, but we do think there is a great deal of thought needs to go into the resource planning process in states where retail access exist.

You have heard a bit about implementation today, and that's where I'll close these comments.

We do support the NOPR goals and we support the speed at which the NOPR would progress, but we are concerned about whether the NOPR can really be implemented at that speed.

There's several things that are absolutely vital in getting the NOPR right. We have to have very accurate system models, and the speaker from PJM discussed those.

The successful expansion of those models is vital. PJM has had a very good system over the years, but it's also a system that needs to be expanded across a number of states and we are concerned about how fast that can be done and at a very basic level we need to make sure that we actually have support systems in place to issue billing that will be adequate, so we support the current time line that you find in the NOPR, but we realize it's a very aggressive time line and we think systems have to be tested before they actually go into place.

We do believe that the FERC should be open to a phased approach if those very aggressive time lines cannot be met. Thank you.

COMMISSIONER HARVILL: Thank you. Next we will hear from ComEd.

PRESENTATION

BY

MR. NAUMANN:

Thank you very much. Thank you for having us to discuss what we think is a major item of importance for the electric industry going forward.

ComEd and the other Exelon companies, Peco Energy, Exelon Generation, strongly support the NOPR on SMD. Even before the NOPR was issued, we advocated the Standard Market Design was inherent in making the number 2000 RTOs work and gratified that FERC has issued a NOPR and set a schedule for companies to meet.

As an aside, we would like to acknowledge and thank Mr. Harvill for his supportive testimony in front of the Senate Energy and Natural Resources Subcommittee or Committee, I guess, last month.

Before I get into our general comments on the NOPR, and I won't have many concerns with the NOPR itself, I need to say that regardless of when SMD goes into effect, or if it does go into effect, depending upon what Congress does, ComEd is joining PJM.

PJM has proven market designs that work, and, as Craig Glazer said earlier, much of the design in SMD is modeled on what is being done in PJM now.

The good news is that in writing the NOPR FERC learned from successes like PJM and they also learned from failures like California. As far as going into PJM, the day one -- what is being called day-one operations transmission service reliability authority going to PJM market monitoring is scheduled now for February 1, 2003.

Day two full market, that include real-time, day-ahead market, congestion management, ancillary services, and PJM taking over the control area function from ComEd would be December '03.

Craig mentioned the implementation agreement was signed, and it was signed and I received a bill, so we are moving and we are financially committed, and I know that PJM people are going ahead.

The backbone of SMD is a bid-based security constrained dispatch with no locational pricing and financial congestion hedges to manage congestion. That's a mouthful, but we keep using these CRRs, and LMPs, and all that other stuff, but essentially it is the kind of system they have at PJM that is a success and that has worked for the customers and that the Commissions who are monitored go to the PJM meetings have found to work.

The system that I'm talking about with locational marginal pricing for congestion management, I don't think there's anyone who would disagree it is vastly superior to the TLRs, the transmission loading relief, we see today in the midwest. That is based on command and control. I mean, TLRs are redispatched. It is someone sitting in an office saying cut that transaction and take care of it the way you want.

LMP with the congestion hedges allows customers to make their economic decisions to serve their load. Now there's a lot of concern that I have heard saying, well, Illinois -- the customers are not exposed to these charges now.

Well, the customers and the utilities are exposed to these charges now. They're just hidden. They're not transparent. A TLR has costs. It has costs by taking a low-cost generation resource and replacing it with a higher-cost generation resource, similarly, if a utility has to redispatch when acting as a control area, you are moving generation out of economic water, that has a cost to it.

What a system like SMD does is it makes the price transparent. It makes the actions transparent and it allows for hedging of these costs which has got to be superior.

We talked about capacity requirements. I'm going to get back to that. That's the one place where ComEd has some improvements we believe FERC could make. You have big caps right now. The big caps are proxy for demand response, and I'll talk a little bit about that.

Market monitoring I think there's been a lot of talk already, but I want to emphasis this is not like going to a restaurant where you can order a la carte. If you talk to people in the business, who are experts on market design, all the elements you have here work together. You can't just say I don't like this particular element, let's replace it with something else. That's how we ended up in California with everybody getting in a room and saying we're going to have a grand compromise, so everyone gets this, someone gets this, someone gets that, someone gets that, but this is a market that we are talking about and it has to function rationally.

SMD is going to put all customers' point-to-point network under the same tariff. Again, that means the utility, as a load aggregator, is taking service under the same tariff as all other customers.

We think that's fair. We think when you get to curtailments and other things, the fact is everybody needs to play by the same rules. Also going into an independent transmission provider, which force the RTOs will be in any case, will help that. We strongly support having all market participants under the same rules.

The other thing is that FERC has gone to great lengths to show, and you can read Appendix E in the NOPR, as to how the design will correct the flaws in previous markets, some of the trading practices engaged in by Enron, the problems with the California model.

So, again, FERC has learned from the failures. You know, the good thing about failures is you can learn from them; unfortunately for the people in California, what we get to learn.

How will this benefit the customers in Illinois? First, and foremost, SMD will result in liquid spot market where market participants can buy and sell energy. That means utilities, RESs, generators, aggregators, end-use load. They can go on the spot market and the day-ahead market, buy and sell energy, and I know some of the issues with the retail suppliers in our territory is buying a load shaping product or penalties for imbalance.

When you get the day-ahead and the real-time market, you are not going to have that problem. You want to load shape, you buy in the market. There are no such things as penalties for imbalance under SMD. There's simply the Locational Marginal Price. You pay it whether you estimated high or low. It doesn't matter.

Second, SMD still supports bilateral contracts between the parties. This ensures stability, and reliability, and allows existing contracts to be supported.

I don't have the statistics. Craig may have them, but I think something like 85 percent of the PJM energy is under bilateral. It's only 15 percent or so in the spotmarket. This is not a California situation where everybody's driven to the spot market and you are subject to this volatility without hedging.

Deliverability, well, that's the problem with the TLRs we have now. That's the problem with transmission service, but under SMD, we have the congestion hedging instrument -- they're called CRRs -- and the NOPR, PJM call them FDRs, New York calls them something else, so we will have to have a new acronym to do that, but, essentially, what the NOPR indicates is that for existing long-term firm uses, that is existing retail, existing RES, existing long-term firm point to point, there initially be an allocation. It will give customers the functional equivalent of the service that they have now. Eventually that will go to auction and they'll probably -- you'll probably hear in the afternoon people pushing auction, and I think once people get experienced with operating with CRRs, knowing how much they're worth, knowing which hedges they want and which they don't want, then we'll come around and support an auction as PJM is transitioning to since they have had experience.

You heard about the idea what happens when load leaves. Exelon strongly sports the position in the NOPR that the congestion hedges follow the load. We do have some details that we think FERC has to work out as to what happens when a load switches, again, when a load returns, so load can't return to a provider of last resort having sold their congestion hedges and saying you are now stuck with us. Those details need to be worked out, and I think -- I think FERC will be open and I think they will want to hear what the states have to say.

The big issue where we think needs some more work is the capacity. The good news, and I really believe this is good news, is that FERC has recognized that there needs to be a capacity requirement to maintain reliability and to reduce volatility of the prices.

Today you can look at MAIN, which does not have capacity requirement, and MAPP, which does. You can look at the MAIN audit and you can see some people have reserves going into the summer and some people don't. It's a recommendation. It's not a requirement.

The problem you get into with the competitive market with load switching is you get free rides. If public utilities have to have reserves and other new entrants don't have to have reserves, you get into a problem of where is the generation going to come from because we are all in this together.

When there's a shortage of capacity, it's in real-time and something has to be done, and that comes to the second clarification or detail that FERC needs to improve upon, the idea that those who are short in real-time can be curtailed does not work in a retail access environment.

As this Commission knows through our unfortunate experiences several years ago, when you curtail customers, you open feeders. That feeder may have ComEd as a supplier. It may have CILCO as a supplier. It may have MidAmerican as a supplier. It may have Ameren or our RESs as suppliers of those customers. We can't just go and say, oh, it was Enron that we are short. We are going to open that customer, so in a retail access environment the idea that you can shut off the customers whose RESs are short just doesn't work, not to mention it could be a critical load, such as someone on the machine.

What you need is a well-designed market, something that's in a sense new construction and avoids the boom-and-bust cycle that we have seen in Illinois.

Some people point to Illinois and say, you know what, you don't need a capacity requirement. You all have had tons on generation and ComEd's connected up 8,000 megawatts of merchant generation since 1999, which we are very proud of, but look at what -- look at before 1999 what happened.

In '99 we had price spikes in the midwest. We saw the price of energy go up to 6 to 7,000 a megawatthour. Now that's plenty of incentive for people to build, but under the constructs that we have, both in SMD, both in the type pools, by FERC action in California, we have had bid caps and, to be very honest, I don't think anything else is politically acceptable, nor do I think market participants will believe anyone who says there won't be bid caps.

To quote someone else, it's kind of like Charlie Brown is not going to believe that Lucy won't pull the football out from under him.

There are going to be bid caps, and so when you have that, you now take away those payments to the generators, which may be for a very, very few hours for peakers, and so if they're going to build, they need to be paid for their investments, and so if you are going to have a bid cap, you need to have something in the form of a capacity market.

Now you have heard some of the problems with the capacity market, the load switching, the fact that what FERC has is not really mandatory. It's just a plan, and, again, we think FERC has come a long way. We understand the balance FERC has had to do because there's a lot of states that are not open access that the states feel we'll just do our old way.

What ComEd and Exelon support is an -- is something different. It's not what they have presently in PJM. It's an improvement. It's called a Forward Resource Procurement Method, and I'll just very quickly just tell you it takes care of a lot of issues that you heard.

The RTO or the ITP holds an auction for the capacity after setting the capacity requirement and after doing the load estimate for the entire region. This eliminates this idea of estimating the load for each load-serving entity.

If we did this several years ago, what would we have estimated the load of Enron as a RES? Well, we know what it's going to be three years from now, at least that we know with certainty. We have a pretty good -- I think everyone agrees that for a large area you could be pretty good on your load estimates. The reserves obviously would be set with the guidance or approval of the states in that region. The auction would be held to establish a clearing price for capacity. The RTO would not be in a market. They're simply acting as the agent.

The good part about that is you could still have bilateral contracts. ComEd can contract for generations to meet its capacity requirements. That provides a hedge against the price of the auction so no one is at the mercy of the auction, and no one need be at the mercy of the auction, and no one needs to have anyone say what their portfolio is. It's simply a matter of making sure there's adequate capacity in the region. To deal with the load shifting when you get into the actual operating period, the TRO builds each load-serving entity their proportional share of the charges.

If they have got bilateral contracts, those are dealt with between them and their supplier as contracts for differences, but it deals with the load shifting. It deals with the reliability. It deals with the forward contracting and it establishes a market price that people can see, so you don't have to worry about penalties. It's taken care of.

Is it a cost? It is the same cost that people face that we have faced for a long time. Capacity isn't free. It's out there and to expect someone else to carry it is not fair in the competitive market. That's really our major improvements on the NOPR.

As far as infrastructure, right now we do have a problem. There are no real price signals given to generators where to locate.

Back in '98, ComEd put out a MAPP and said to generators here is where we like you to locate, and out of those 8,000 megawatts, I'd say about 1,000 megawatts located in a place we really wanted them and a few thousand megawatts located in a place where we really didn't want them. That's fine.

Today what happens. You locate there. You want to serve -- and this is the truth -- you want to have the generation served in Wisconsin, Commissioner Kretschmer said earlier under the pricing policy right now, cost out of that line gets paid by the Illinois consumers and SMD is going to take care of it.

First of all, the generators are going to get the price signal, so they may not want to locate here if they want to serves Wisconsin. It may cost them a bunch because of constraints in Wisconsin.

Number two, building transmission now as a price signal. Do you know what the difference in a locational price is? So if someone wants a line built to lower their costs, you know if it's worth it.

We keep hearing we need more transmission. We need more transmission. I don't disagree, but we need the right -- you don't need transmission at any cost, because sometimes there are far less expensive solutions.

So by showing the locational prices, you know what you can save by building transmission, which brings me to a last point, and here's what we do take issue with some people, especially a talk given by the Wisconsin utilities last week.

We believe in participant funding. We believe in the principle that those who cause the expenditures should pay, and so if ComEd causes the expenditures to serve its load, that's fine, we should pay, but if Wisconsin need a 345-line built between here and Wisconsin, the people of our service territory should not pay for that line when it's being built to lower those costs. That's simply unfair. The NOPR supports that. FERC even made a stronger statement last month in the -- last week. I'm sorry -- in the C-Tran (sic) order.

When the commission made the rulemaking, they realized that it was complex. They realized people would have comments, and they obviously are open to those comments. They have held regional meetings. They're holding more workshops and on some of the controversial issues, there are going to be technical conferences.

On some of the issues that I have mentioned that are I think very important for the state, the capacity issue, the initial allocation of the CRRs, the CRRs following the load, those issues there are going to be technical conferences and we think they can work with the Commission on establishing positions that are both good for Illinois and good for the market.

Some people are taking the position, mostly in the southeast and northwest, and I understand, Commissioner Kretschmer, the governors are important, because they are the governors, but we need to deal with the midwest and there are people who are saying this is wrong. Well, that's what the administrative process is for. This is a notice of proposed rulemaking.

There is a process, including the technical conferences, the meetings, for everybody to put in their comments for FERC to hear where people come down on, and it seems that that's where people should focus instead of just saying it's wrong, it's bad. As I have tried to say, I think it's good. It's good for Com Ed. It's good for the customers. It's good for Illinois.

Does it need tweaking? Everything -- nothing's perfect, but as a whole, it's a very good effort by FERC. We think the Commission should support it and we would like to work with the Commission to find ways to support it in front of the FERC. Thank you very much.

COMMISSIONER HARVILL: Thank you. We are going to continue on with Illinois Power.

PRESENTATION
BY
MR. SCHUKAR

Thank you. Illinois Power would also like to thank the Commission for their interest in

SMD. We also believe the SMD is important moving forward in this market and is one more important thing is coming down the road for us.

Just as a backdrop, Illinois Power is maybe somewhat different in that we have divested our generation, some of it to the affiliates, others to non-affiliates, and we have just recently announced divestiture of our transmission.

As a result of that, Illinois Power will be a distribution company focusing on distribution. We will retain the provider of last resort and the requirement to serve the customers in our territory and serve the distribution customers in our territory.

As a result of that, we will be taking transmission service from the RTO, as others would have, but we will no longer have that interest in the transmission.

We will be buying all of our power through power purchase on the open market or spot market, but we will still have that provider of last resort and the capped rates in our territory, and because of that, we have some concerns, but our overall position with the SMD is that it's a very positive move forward and we believe that it is well worthy of moving forward in the marketplace.

The positive aspects we see under this, first of all, everything takes load under the same tariff. That's what was going to happen under the RTO, but the gas industry -- when everybody was put under the same tariff, the rules became much more competition-friendly and we believe having everybody under that same tariff is a positive.

The independent control of the transmission provides a confidence to the marketplace, and whether things happen today with integrated utilities or not, the marketplace doesn't have that confidence, so to get it to an independent company is a very positive forward move in the marketplace.

The LMP Design and with congestion rights, I think that the other speakers have spoken with very well as that is a step forward in our marketplace. It provides pricing indications at the location. It provides incentives for the price indication of whether to either add generation or add transmission, and from a utility that will be purchasing in the marketplace, it gives us another option.

The spot market today, the hedge market is one more option. As ComEd mentioned, it doesn't stop us from entering into bilateral contracts, which is where Illinois Power believes that they will do much of their work, but it give us the other option in the marketplace of going to the place to supply for our end-use load.

Also, as CILCO indicated, since we will now be subject to the difference between what we have scheduled or what we plan to do and what the actual loads are, having a market to provide a very definitive market price for us is an improvement in the market over the imbalance market types that we have today in the market.

The other areas that we see as positive is standardization of rules and information systems across the system, so as ComEd, and Illinois Power, and Ameren were all on the seam between MISO and PJM today, having common systems in place will enable us to do business across both markets and we see that as a very positive.

And last of all the transmission planning and having a regional transmission plan is very important to gain the best solution.

In today's market, while we coordinate for regional transmission planning, when it comes down to things like generation, interconnections, and that, typically most of the providers look at their own system and they may provide information to the other providers. We come up with our other solution and they may come up with a different solution.

Moving forward with everybody working together, that just integrates the solution and hopefully gets to an answer quicker and one that's a better solution than just a small utility, like Illinois Power, providing that solution; however, there are some areas that we believe do need to be looked at, and specifically one of our main concerns has to do with the retail and how retail is addressed in the state at the same time we go into the single market, the congestion revenue rights and how the allocation works and how that works with the retail choice, transmission pricing, system adequacy, and market mitigation.

The congestion revenue rights we believe there is an argument both for allocation and auction. Auction provides probably the best signal to the marketplace of what is the congestion and holding that hedge out there; however, from a utility that will have the responsibility to continue to supply load, we want to ensure that we are financially held whole as you move forward in the marketplace.

We believe that the allocation initially provides us some protection, although, as Ameren has indicated, as our resources in that change, that does create some issues for us, but auctioning it off into the marketplace provides a signal to every supplier and as you have more RESs in your territory come in and compete for load, having those pricing signals out there is very important for that marketplace to be a viable marketplace. The allocation also protects us.

I know that there's been some discussion in the NOPR of potentially cutting load and giving preference to the holders of CRRs. As Steve, or Mr. Naumann, indicated earlier, in the retail choice state, you can't differentiate when it comes time to cut load out there. And when you get to the point where there isn't adequate resources in the marketplace and you have to shut off load, I can't go out there and identify that, well, Illinois Power didn't have enough, so I'm going to cut their customers because we're going to open up part of the system and it's going to get whomever is providing for those customers, so we see that as an issue -- a protection issue that needs to be looked at as we go through retail choice states.

The NOPR looks at allocation of the CRRs in following the load. While in general we think that is the best thing of the auctions that has been put out there, there are some things that we need to look at in detail to ensure that they adequately do address.

ComEd indicated the idea if somebody left the CRR solely and then come back to the utility, somehow the utility has to be protected or the customer has to acknowledge that they no longer have that CRR and would be the ones responsible for the congestion in the marketplace.

The other issue -- and when Illinois Power looks at it, we supply from resources internal to the Illinois Power control area and some are external to our control area.

If someone wants to come in and compete for our load, they're not going to necessarily use the same resources that we used, and so a CILCO, who's competing in Illinois Power territory, comes into Illinois Power they may want to use resources that our congestion hedges don't really work for, and so there's some issues with what happens when customers leave whether the CRRs are the right ones for them.

The other issue is the provider of last resort, and, as I indicated before, when a customer leaves and comes back to Illinois Power, they can come back today under capped tariffed rates, and as they come back to us, if there is not -- say they left and entered a proposal and they left and they had CRRs and they swoped them for CRRs to other resources but then come back to Illinois Power and the resource that they had previously used is unavailable, because that supplier has decided to use that resource somewhere else, and that CRR really doesn't provide the value to me that getting another resource may provide from what's available in the marketplace. So with the provider of last resort, I may be exposed to either hedging risk out there that I wouldn't have today if they just stayed with Illinois Power.

So as we look at the NOPR and the implication here in the State of Illinois, because of customer choice, we need to ensure as customers switch back and forth that we fully understand the implications of the CRRs that follow -- that may follow the load, and also I'll speak to later capacity requirements, if there are any capacity requirements.

Transmission pricing is another issue for Illinois Power. While we believe, in general, signal market design and having a larger marketplace out there is a positive and is good for competition, when I think about competition, I think of two things that occur out there. One is prices get lower and, secondly, customers have different options and different choices than what they have today under a bundled rate.

When FERC asked for a study of RTOs and what the implication was for RTOs, the study showed that in the lower MAIN region that the costs would potentially go up, and so from a company that has the capped rates, we are concerned that costs may go up somewhat in our region and that there's a cost shifting associated with the transmission

Illinois Power's current transmission rates are very low and they're relatively lower than most in the region. In fact, if you look at some of the rates out there with our neighboring utilities, they're more than doubled Illinois Power's transmission rate.

About 30 percent of our revenue requirement is tied to what we would currently think of as through-and-out rate, and so when generations moved off of our system, or whatever, that's a reduction in what the customer's Illinois Power territory are responsible for.

If the rate structure change such that all of those costs come back to our customers and the RTO study was accurate, then the cost to the customers in our territory could be negatively impacted.

The other issue associated with transmission pricing is the upgrades to the system and Illinois Power has a concern. Based on what we currently know, we have independent power producers who are looking at attaching to our system with upgrade costs in the range of $50 million, our total current net book on transmission about 142 million. And so if a generator comes on-line and causes upgrades on our system of 50 million and that all went to the local -- excuse me -- the local customers, you would see a 25 percent rate increase for those customers, and because we already have enough generation, that could either come in or can be brought in from other marketplaces, they would take the brunt of their increase and really wouldn't benefit significantly from what's happening from generation availability in the marketplace.

So we believe that the cost -- the

persons who benefit from the upgrade in the system are responsible for those costs and should be the ones who carry that cost going forward.

System adequacy is one other area that we have concern, and much of our concern -- there's two areas of concern here. One is the three-year forward look in a state that has choice. How do you follow that capacity and ensure that somebody who leaves and then comes back maintains the capacity, and ComEd talked to the three providers out there.

It is entirely possible under our current retail rate design that somebody could leave, take the capacity requirement with them and right prior to the summer period, they drop the load back to Illinois Power under one of our riders and then we would be potentially responsible for the penalties.

We find that very, very disturbing and want to ensure that if there's any capacity requirements out there that there's someway to tie that to the loads who are leaving so they continue to have that responsibility with the load.

The other area that kind of ties to

capacity is around market mitigation and the price cap of the marketplace. As Commonwealth Edison discussed, we believe also that for there to be a vibrant generation market that the generation needs to have the right price signals out there, and we do not believe that the thousand megawatt or thousand dollar per megawatt cap without a capacity market provides the right signal, and I know that in the NOPR one of the things that is discussed is a cap continues to exist until we have customers with demand response.

Our experience back in '98 and '99 when the prices went to the 5, 6,0000 range was that very few customers are willing to respond.

Now we have some interruptible contracts where large industrials respond to that, but, in general, many of the customers that we talked to at that time to get the response in the thousand dollar range were unwilling to do that and the price was much higher, so we are concerned that by having a thousand dollar per megawatt cap where many customers won't react, we will continue to have that cap out there and you lose the demand response that you may need in the future, so we think that we need to look very closely at what is the right cap price to have.

In addition, we are very concerned that we don't send the right signals to add new generation. Back in '98 and '99, generation capacity was low. Prices went very high. I was sitting on the desk the day we had to buy the 5, 6000 per megawatthour stuff and I could tell you it was a very uncomfortable feeling, but at the same time those price signals is what drove the capacity development here in the midwest and as we now see we have plenty of capacity.

And so if we take away those price signals to the customers, I'm concerned that we will get back to a place where we don't have enough capacity or we haven't sent a signal to maintain a generation market that's very competitive.

So we think it's very important that whatever pricing mechanisms we have out there sends the right signal to generation development and also for the transmission development to move that generation to the marketplace.

I guess in conclusion with all that said here is that we are supportive of the SMD. We think that the common market and Standard Market Design is important for a competitive marketplace; however, some of the issues that do need to be addressed as far as the adequacy and market mitigation are very important to make this a viable market, and that concludes my comments.

COMMISSIONER HARVILL: Thank you.

Questions from the Commissioners? Commissioner Kretschmer.

COMMISSIONER HURLEY: It's a lot.

COMMISSIONER KRETSCHMER: First of all, I would like to thank all the participants, because you gave a very thorough overview of the issues.

I would say, without any fear, that I share the concerns that Ameren has expressed, especially the postage stamp and license plate method using caution that they do.

I also share your concern about improper price signals resulting from cost shifting and certainly manufacturers (sic) may not be charged for upgrade requirements to the system. I think they are very important concerns.

I have one question for CILCO. You mentioned long-term contracts. I remember when long-term contracts meant 20 years, 15, 10 was a short term. What kind of a long-term contract are you discussing? How long is long?

MR. FERLMANN: Long-term now is in excess of one year. Primarily for us, it's anywhere from three-to-five years.

COMMISSIONER KRETSCHMER: Three-to-five years for you?

And Com Ed mentioned the same thing, long term contract. How long are long-term contracts for Com Ed?

MR. NAUMANN: Well --

COMMISSIONER KRETSCHMER: This is obviously for supply.

MR. NAUMANN: I had to get the advice of Exelon Generation --

COMMISSIONER KRETSCHMER: I saw you consulting.

MR. NAUMANN: -- because we contract with them for generation, but I'm told that three-to-five years is the order -- same order of magnitude CILCO has said they would contract with suppliers.

COMMISSIONER KRETSCHMER: Now let me ask a question I don't know the answer to, and I'm really going to be fumbling even asking the question.

When all of you are buying on the spot market, are you going to have to have reserve capacity on the transmission system in order to buy on the spot? I mean, if you buy on the spot someplace where there's congestion and you are buying, how will you get the transmission if they're not alerted ahead of time? How is that going to be arranged?

MR. NAUMANN: I think we are looking at a completely different regime than we are today where today you reserve transmission from known sources.

When you have a spot market operating the way they do in PJM, New York, and New England, what you end up having is suppliers bidding into the spot market. Those bids that are reflected in these locational marginal prices and the generation is the dispatched based on their bids subject to, what I said earlier, a security constraint dispatch, that ensures the deliverability of the generation from the spot market. It simply sets the price based both on the price of the energy itself at the places generated and the cost of congestion is then -- is then integrated into that total price into the locational price that you take when you withdraw power from the system. It's got kind of a different way of thinking from where we are today. It's how it works in PJM. Am I right, Craig?

MR. GLAZER: (Nodding head.)

MR. NAUMANN: I'm getting an okay that I explained it correctly, which is good.

COMMISSIONER KRETSCHMER: Let me ask you a follow-up question. Let's assume you can buy on the spot in a given area of the country and spot is pretty good in that area. What happens if the congestion factor kicks in and makes the contract for the supply higher than you if you gone somewhere where there was no congestion on the transmission? Could that happen?

MR. NAUMANN: Yes.

COMMISSIONER KRETSCHMER: So you would be getting two prices, one for the supply and one for the transmission? You could get them both?

MR. NAUMANN: It can happen just like it happens today. Today what happens is -- for example, let's first assume ComEd generation is into gas on a particular day and Exelon Generation finds a coal generator or more efficient gas generator to buy out, you know somewhere in the coal fields of Appalachia. Obviously, the price of energy in Appalachia is cheaper under those conditions than the price in Chicago --

COMMISSIONER KRETSCHMER: But you may not be able to deliver.

MR. NAUMANN: -- but you may not be able to deliver.   So today what happens is we either don't get to deliver it -- that's a service denied -- or you start delivering it and you get curtailed. That's the dreaded TLR.

What happens under the SMD system is you get a price signal as to the cost of congestion for delivering it and you now can make an economic choice as to whether, considering all of the congestion costs and the energy costs, it's still cheaper to deliver from this resource or another resource, and that's so much better a system because you, as the customer, get to make that choice as on visible prices.

COMMISSIONER KRETSCHMER: Let's just hope it works as easily as you stated that.

Just one more group of questions. You said you had 8,000 new megawatts of generation since it has been added to the ComEd system. Is that right, the number 8,000?

MR. NAUMANN: Eight thousand -- spending 8,000 new megawatts, merchant, all in-service, operable.

COMMISSIONER KRETSCHMER: Is that all gas-fired?

MR. NAUMANN: It's all gas-fired. A large part it is a simple cycle. Some of the newer generation that's come on or combines cycle gas.

COMMISSIONER KRETSCHMER: Do you mind if I ask --

COMMISSIONER HARVILL: No. Go ahead.

COMMISSIONER KRETSCHMER: IP, you are going to be -- you are not going to own any generation, and if your sale is approved, you won't own any transmission.

How are you going to ensure that you are going to have sufficient supply in cold winter days if congestion starts mounting up and you have got firm contracts or supply over here and congestion is there and you have got to go over here? How is that going to work? You don't have either one now.

MR. SCHUKAR: Well, there's two parts to that, and I think in the conversation you just had with Mr. Naumann, there's the supply and where we contract for supply, and we can either contract in bilateral agreements or we can go to the spot market and wherever we buy from presumably we'll look if there's CRRs that are available to protect us from congestion costs.

We will either allocate those or we'll look to paying those in the marketplace, and that will protect us from pricing perspective -- and that hedges us from a price perspective.

The other part of the question I hear you asking is how do we insure the liability, and that's kind of a regional question, because what will happen is if there's enough generation available, generation will be dispatched such that we'll get the power to our customers and the question that really occurs is does Illinois Power pay more price-wise for congestion, because the resources are different resources, or will we hedge against that.

What happens if there isn't enough generation in the region? And part of what I was trying to address in my comments is that we would have to curtail customers or the transmission provider would curtail customers, and because you can't distinctly say it's only Illinois Power who is short, it may be partially Illinois Power customers. It may be IMEA's, who's in our territory, customers, so it could be several people who are impacted by that if there isn't enough adequate generation resources in the area.

COMMISSIONER KRETSCHMER: When you start doing the fuel adjustment clause for a company that doesn't own any generation or any transmission, I wonder how it's going to interfere or add to the work that's necessary to do a fuel adjustment clause to make sure your customers have not been harmed by you becoming just a distribution company. Have you thought about that?

MR. SCHUKAR: Yes, I have since I'm on the supply side. We are very concerned with a TGA style of the rate going forward because there's two dynamics to that. One, if you allocate CRRs and you have a TGA style, then there isn't a lot of incentive for me to go sell the stock into the marketplace because then what ends up happening is I sell it to the marketplace and something changes and I lose generation and then my locational price goes up and I get disallowed because I sold in the marketplace. That's not a very good position for me to be in.

The other part of this with customers having opportunities to come back to Illinois Power and/or leave Illinois Power, is how are we looked at. If I say that I estimate that 30 percent of our current load leaves and then 50 percent leaves, and I had gone out and contracted for additional generation and CRRs, and I sold them into the marketplace, and I got some of it back, how am I going to be looked at from APGA or fuel adjustment clause-type of mechanism to say was I making a pretty good choice or not, and so I think there's a lot of issues around there.

COMMISSIONER KRETSCHMER: I'm sure our staff is looking at that already. Thank you very much.

COMMISSIONER HARVILL: If we could, before we go onto other questions, one of you, and I don't care whom it is, could you kind of walk through, from an educational point of view, how LMP and CRRs will function together, Steve, or whoever wants to tackle that.

What I'm trying to do is make sure the Commission understands what LMP is, how those prices are set, and what CRRs are, and how they actually function essentially.

MR. NAUMANN: Why don't I take a crack then. Anyone who -- I'll try to get it right. I'm sure there are other experts that will correct me.

In a way, they are two separate things that work together. CRRs are financial congestion hedges, and what happens in PJM now, and I would anticipate under SMD, is that PJM does an analysis of the system going forward. It says what can the system do. Individual customer come to PJM and they say here's where I have my generation. Here's where I have my load. Here is where I would like my congestion hedges.

Now there's some rules to that. You can't have more congestion hedges allocated to you than you have load. That would be hording. PJM takes the wish list, so to speak, runs it through a system analysis to see if it's what's called simultaneously feasible. That's the mathematical word to see that -- the fancy mathematical word to say does it work.

If it's simultaneously feasible, everyone who is asked to do these particular CRRs between points will get them allocated. If it's not, there has to be some pro rata cutback, but that's no different than today when people have service denials.

The CRR, or in PJM calls an FDR, allows you to receive a payment for congestion between the two points of the CRR, so for ComEd -- let's say ComEd asked for the CRR between Quad Cities and Lombard or way off load sector. You have this book of CRRs.

Now in the day-ahead in the real-time market, the generation again is bidded, the RTO solves the security constraints dispatch equation based on those bids and the transmission limitations and comes up with a dispatch that satisfies all those conditions, which, in effect, is what private utilities used to do for their own system, although maybe a lot of people on board kind of just knew that that is the way you dispatch the system.

Each dispatch then, based on those bids, ends up with a nodable (sic) locational marginal price. In the absence of congestion, all nodes (sic) would have the same price, a little different for loses.

With congestion, you will have a higher price at one end than another end because you would have to run higher cost generators on the constraining side.

A perfect example of that is New York City. New York City has older generation, oil-fired generation. Upstate New York has nuclear and coal and you cannot serve old load in New York City with the nuclear coal because there's simply not enough transmission to bring it in, so the prices in New York City are somewhat higher than they are in Albany.

What happens is -- and I'm -- there are other people who are far more knowledgeable about the settlement system -- the details of the settlement system can tell you much more than I can, but essentially what happens is when you schedule on a path, you schedule between two points, and there is a charge, the difference in the two LMPs, so let's say the LMP at the point you injected power in was $20 and point you took the power out was $30. That has a congestion charge of $10 that you would have to pay.

If you hold a congestion hedge, a CRR for that series of points, you pay the $10, and as the holder of the CRR, you get the $10, so effectively you have hedged your congestion.

Now in a perfect world you have exactly the right CRRs for every specific point of receipt and point of delivery, but that's what happens. You face congestion, then you have a financial instrument that allows you to essentially receive the congestion payments to hold you as -- to let you hedge the delivered costs of power as close as you can within your ability to hedge and, you know, the fact that a unit tripped and you now have to go out and buy power from somewhere else, there may be congestion. That, in short, is how the LMP works with the CRRs.

COMMISSIONER HARVILL: Should or does the FERC envision CRRs reflecting physical constraints on a transmission system or should they I guess is the better question?

The point I'm trying to get to is this. If you as Commonwealth Edison -- all CRRS are allocated to you initially between two points and load increases and new generators come on-line and want to serve load on that same path. You, as Commonwealth Edison, hold all of those CRRs for that particular line. There could be a situation where there wouldn't be any CRRs available for that new load to hedge against the LMP.

MR. NAUMANN: Well, I think there's two questions, Commissioner Harvill. The first is load growth and the second is load shifting. The easier question -- I think they're both easy, but I think the easier question is load shift.

The Commission proposed that as load

shifts the CRRs go with the load. Now that's a very nice statement, and I think I have heard pretty well support, and I think we all agree that needs a whole lot of flushing out exactly what that means, but we have talked about it with Exelon.

We think when you eventually get -- sorry for throwing in another acronym -- ARRs, Action Revenue Rights, rather than the actual CRRs, the accounting becomes a lot easier because, to be very crass, it's just money. So that if a customer leaves and 20 percent of the load leaves, they get 20 percent of the Auction Revenue Rights and then they can go in the market with that money and buy the CRRs they want. That's why we think there needs to be a transition to the auction, but you -- we also understand that people need to get experience with the CRRs. It's more difficult when you have CRRs.

What we envision, and I think as talked about it at PJM, is there's some release, then there's proposed refiguration on new load based on sources that the load has. It may not be simultaneously feasible. There may have to be adjustments for load growth.

There are really two issues. First is you have got to have enough deliverable capacity to serve the load, I mean, otherwise, it doesn't get served. In general, that means there is going to be sufficient transmission to serve the load. As you add transmission to serve load, and I think all of the Illinois utilities have been outstanding in building transmission necessary to serve the load growth.

That's not one or our primary responsibilities. You get additional CRRs, because you get additional capacity. You have additional simultaneous feasibility

Now could you in theory end up with a situation where you develop a load pocket for a short period of time? You have to operate an old coal-fired generator, sure, but that's where the LMP now starts giving the price signals to correct that, and I would also add that's no different than a utility today faces than if you have load growth in a -- you know, again, I use the New York City example. It's easier. It doesn't pick on any of us. If you have load growth in a constrained area like New York, yes, you are going to have congestion. The price is going to be higher until you build transmission, but, again, as I said, that's a situation we face today until you can build more transmission to bring in the lower cost generation. I don't think this makes anything worse than it is today. I think it makes it visible, whereas before it was invisible n the control area of operations.

COMMISSIONER HARVILL: Thanks. Other questions?

COMMISSIONER HURLEY: I have nothing.

COMMISSIONER HARVILL: I just have one question, actually two questions. I'll go to Illinois Power first.

You have stated your intentions to divest your transmission assets to TRANSLink I believe.

MR. SCHUKAR: Correct.

COMMISSIONER HARVILL: That being the case, any attempts made to migrate PJM to the MISO considering most of TRANSLink and all TRANSLink transmissions is in the MISO or do we even know what's going to happen there?

MR. SCHUKAR: Right now, you know, I anticipate we'll stay with the PJM.

COMMISSIONER HARVILL: The other thing really isn't a question. When I think of Ameren, I get rather upset just simply because -- not because of the company or what you do, it's because of that banner on every San Francisco Giant home run went over that banner in left field. Could you do me a favor. During next year if you have that banner, could you move it into foul territory for me.

(Laughter.)

MR. WHITELEY: There's good and bad with advertising. It's who hit the homerun over the banner.

COMMISSIONER HARVILL: Thank you very much. If there are no other questions, we are going to break a little earlier. We are going to reconvene at 1:30.

COMMISSIONER HURLEY: Commissioner Harvill --

COMMISSIONER HARVILL: Yes.

COMMISSIONER HURLEY: -- I should point out to you that you did indicate that you were going to allow questions from the audience in the event people out there are wondering if they have could, however, I see a lot of sleepy faces. Maybe it is time to go to lunch.

COMMISSIONER HARVILL: In any event, I will make an offer right now if anybody has any questions or comments. I see nobody rushing to the microphone. I think they'd rather have lunch.

COMMISSIONER HURLEY: I think a wise move.

COMMISSIONER HARVILL: Thank you again for all of our panel members. I appreciate your coming here. We will reconvene at 1:30. We are off the record. Thank you very much.

(Whereupon, the above matter was adjourned, to resume at 1:30 p.m.)

We are going to go ahead and begin. We are going to go back on the record.

This is a reconvened meeting of the Illinois Commerce Commission called as an Electric Policy Meeting to discuss the FERC Standard Market Design.

We'll continue on with the agenda, as

published, with one exception, and today's panel beginning at 1:30 we have one addition, Jacob Williams, Vice President of Generation Development from Peabody Energy will be added to the agenda, so he'll follow-up in order.

Today we have representatives from the generation and marketers sector. I'm just going to read through who is actually going to be making presentations this afternoon. They will go in that order.

Representing Exelon Generation Company we have Ms. Regina Carrado -- I hope I am pronouncing it correctly -- representing Edison Mission Energy and Midwest Generation, Reem Fahey; from Constellation NewEnergy, Julie Hextell, and from Calpine Corporation Mr. Vito Stagliano; and from Reliant Energy, Patty Harrell. Of course, Jacob Williams will follow-up at the end.

That being said, I'm going to turn things over to Exelon to kick things off and we'll go from there. Thank you very much.

PRESENTATION

BY

MS. CARRADO:

Good afternoon, everyone. Thank you for this opportunity to speak to you today.

CHAIRMAN HARVILL: Could you move the microphone a little closer.

MS. CARRADO: Sure. I'm a regulatory specialist with Exelon Generation and I have also spent 15 years in transmission planning, so that's more years than I would like to admit, but here I am today.

Exelon Generation is the subsidiary of Exelon Corporation that is responsible for electric generation and wholesale trading. In addition to managing the generation assets, we have the responsibility of providing for energy to meet Exelon's distribution load in both Philadelphia and Chicago through long-term power purchase agreements.

Earlier Mr. Naumann summarized some of the key aspects of SMD and provided insight as to why SMD will benefit customers in Illinois. I would like to take this opportunity to elaborate a bit more on

Exelon's position in three areas: Number one, resource adequacy; number two, the day-ahead in real-time markets; and, thirdly, market monitoring and mitigation.

Moving on to resource adequacy, we believe the SMD proposal have a capacity requirement which includes several positive fundamental features, such as state involvement in setting the reserve requirements, a longer planning horizon to promote resource competition, equal opportunity for both generation and demand-side resource, and a deliverability requirement so resources are deliverable through the transmission system to the load.

Nonetheless, as Mr. Naumann and others have elaborated today, we believe that the specific method proposed to determine how LSEs will meet their capacity requirements is unworkable in a region with retail choice. Longer planning horizons for the regions are necessary; however, LSEs inner-region with retail choice do not know in advance of the operating year what load they will be serving.

That's kind of been a common theme we have heard today. We know the forecasted load for the region, but we don't know which load each individual LSE will be serving.

Exelon believes we have an alternative that will work and we call that the Forward Resource Procurement Method, or FRPM, if you will. Under this method, the IPT acts as an agent in contracting the resources needed for the future planning year via a centralized auction and then charges the LSE in the operating year based on the actual load they are serving. Such a prorated charging mechanism appropriately charges LSEs their fair share of the region's obligation when, and if, customers switch from one LSE to another, thus, this method enables the region to arrange for a committed capacity well in advance of the operating year.

As with the FERC proposal, this method uses a planning year sufficiently far enough in the future to allow the entrants to build resources and thereby ensuring liability while preventing exercise of market power and setting resource clearing prices.

Also, under this method, resources and LSE owners can still enter into bilateral contracts.

Exelon believes that FRPM is a viable market-based model that will best fulfill the vision of FERC resource adequacy requirements in the SMD. It will help ensure that the Midwest has a reliable liquid capacity market that will encourage a new infrastructure. We seek the support of the ICC in promoting -- to petition FERC to adopt the FRPM methodology.

Moving on to the day-ahead in the real-time markets, not wanting to put forth the notion that these concepts are simple, they're very complicated, but I would like to think of them in simple terms, and when I think of resource adequacy, to me it's taking care of business to make sure that the reliability needs are met and future loads can be served.

My analogy for the day-ahead and real-time marketis is if you build, they day will come. If you have viable markets that work, you will get new players and new products in that market.

As proposed on under SMD, the fundamental elements of the two settlement systems are a day-ahead, bid-based security constraint energy market, and the real-time balancing market that is the least cost constrained dispatch across an entire region.

Both PJM and New York ISIS (sic) have operated both day-ahead and real-time markets for a number of years and they have been successful.

Exelon supports the ITP running a voluntary day-ahead market with the design that encourages market participant choices. A well-rounded energy market, which is the hallmark of SMD, consists of bilateral contracts, the ability to self-schedule, and also to lean on centrally administered LMP markets with the ability to settle at either a day-ahead or real-time prices.

Now that's a mouthful, but essentially generators and load serving entities are provided with many options to procure energy and can make the right economic choices based on their needs and risk profiles. These choices enable load serving entities to opt out of the ITP central markets by self-providing or by engaging in bilateral transactions.

When the PJM market was first instituted, there was only a real-time spot market. Although it was very successful, market participants wanted a away to hedge against volatile real-time prices. The day-ahead market allows market participants to lock in energy prices based on the day-ahead locational marginal price values.

For LSEs needing to purchase energy from the central market, they can and are incented to bid on their next day forecasted load needs to the day-ahead market. Imbalance is treated and paid for because deviations from the day-ahead market are settled at the real-time prices.

One final comment regarding day-ahead market that I wanted to explain was that although this is a voluntary market, there is a hook to resource adequacy, and it's a very important hook.

Resources that have been committed to the region and are designated as regional capacity resources must either bid into the day-ahead market or be available self-schedule.

Even if regional capacity resources are not scheduled to run in the day-ahead market, the ITP can call on the unit in the operating day to run to meet energy needs.

If the resource is running but the energy is being sold off system, if that resource is a designated capacity resource, the ITP has recall rights on that energy and can recall that external cell to serve the local needs of the region.

Moving on to market monitoring and mitigation, the best thing I can come up with on that was that big daddy's watching

A functioning competitive wholesale market must have clear market rules and a well-defined market monitoring function. We believe that a competitive wholesale market will benefit customers. To achieve that benefit, every stakeholder, the regulators, consumers, and investment community, and the wholesale resale participants themselves must have complete confidence that the market it is functioning efficiently and in an open nondiscriminatory manner.

We feel strongly that the market monitors should monitor the ITP management, actions of transmission providers, NITCs, and behaviors of load and supply participants.

The market monitors should deal with harmful behaviors by attempting to achieve settlement and/or reporting the behavior to appropriate entities for remedial action. The market monitor should identify market flaws and work with the RTO and stakeholders to find a solution.

The MMU should not have enforcement or penalty authority. We believe that FERC should have that authority. FERC should oversee the MMU and establish due process procedures such as rulemaking and enforcement proceedings. The MMU should not monitor the ITP and market participants to ensure compliance with rules. FERC establishes and practices the ITP develops.

We believe that for the most part market monitors in existing ISOs are performing their roles appropriately; however, improvements would enhance the competitive environment.

Current challenges facing market participants, such as Exelon, are the lack of consistency in defining and measuring market power, the lack of consistency across regions with respect to mitigation -- for example, how do you define economic withholdings? How do you define physical withholding? -- the lack of ability when there is mitigation to recover both fixed and variable costs, the price you are mitigated to needs to be set at the right levels so a generator is assured that it can recover its costs, and the lack of clearly defined and appropriate roles for the MMU.

The MMU should not attempt to design new markets. Unilaterally imposed rule changes were performed in enforcement activity.

The good news is that there are several initiatives underway to address these varying across the regions in these challenges and we are actively participating in them.

In conclusion, regarding market monitoring, I would like to emphasize that not all violations of market rules are equally harmful. We have categorized them into three areas: First there are mistakes due to lack of training, fat fingers, what have you.

Secondly, there is exploiting loopholes and creating significant adverse impact on the market.

Thirdly, there are clear and blatant violations.

We believe that the MMU should identify the behavior and determine the category of the violation and react differently depending upon the level of infractions.

Exelon has significant experience working with competitive generation and distribution load commitments in an organized wholesale market structure and in a region with retail choice.

We enthusiastically support FERC's SRD initiative. We hope that the ICC will agree with our positions, especially on the important issues of resource adequacy methodology, standard day-ahead market and real-time markets, and the role for effective market monitoring and mitigation.

ICC comments to FERC when these issues are likely to be given substantial weight by FERC as they consider how to have draft their final rule on SMD.

Thank you very much and I look forward to your questions.

CHAIRMAN HARVILL: Thank you very much.

Next we'll hear from Reem Fahey from Edison Mission Energy and Midwest Generation.

PRESENTATION

BY

MS. FAHEY:

Good afternoon, Chairman Harvill. Thank you for the opportunity to participant in this important discussion before the Commission. I'm Reem Fahey. I'm the Director for Market Policy for Edison Mission Energy, which is the parent company of Midwest Generation.

Midwest Generation is a Chicago-based company, which owns and operates about 9400 megawatts of fossil fuel capacity in Illinois, which was acquired from Commonwealth Edison in December of 1999.

Exelon Generation, which purchases power for ComEd, has opted to regain 4700 megawatts of this power under the Power Purchase Agreements for 2003 and has released the remainder from contract.

Edison Energy and its subsidiary, Midwest Generation, generally supports and endorses FERC's Standard Market design as the initiative.

The featured proposal that's related to the structural design of competitive wholesale markets are well-founded and a significant step in the right direction.

EME has provided detailed comments addressing specific issues requested by the Illinois Commerce Commission. These comments are provided in my handout, however, this afternoon I would like to focus on three main topics: Practical implications of first Standard Market Design for the State of Illinois, resource adequacy, and transmission pricing.

First, in regard to the practical

implications of FERC's Standard Market Design for the State of Illinois, the State of Illinois requirement for Illinois utilities to participate in an ISO as part of the enactment of the Illinois Restructuring Act, Illinois potentially can be well on its way to complying with FERC's SMD initiative. This, of course, can only be achieved if the Illinois utilities fulfill their announced intentions to join either PJM or the Midwest ISO.

PJM is already fundamentally compliant with the main aspects of the FERC Standard Market Design. As a matter of fact, FERC used the PJM market design as its template and blueprint in their proposed rulemaking.

In addition, the Midwest ISO will also be fundmentally compliant, given that its market structure is a replica of PJM's successful market; however, none of the competitive benefits envisioned by both the Illinois Restructuring Act and FERC's Standard Market Design can be realized without the Illinois utilities' prompt participation in PJM and the Midwest ISO.

We urge the ICC to remain focused on that specific task. Specifically, we urge the Illinois Commerce Commission to work with FERC to ensure that Illinois utilities comply with the FERC's July 31st order as follows: Join either the Midwest ISO or PJM by yearend; be fully integrated in the energy market by year ending 2003; eliminate rate-pancaking between MISO and PJM; and, finally, creating a single common energy market between PJM and the Midwest ISO.

If this is accomplished both FERC's Standard Market Design initiative and the ICC's objective of creating a successful wholesale and retail energy market, as envisioned by the Illinois Restructuring Act, will certainly be achieved within the State of Illinois.

It is imperative that the ICC not allow FERC's Standard Market Design initiative in any way to hinder or delay ongoing effort of both PJM and the Midwest ISO in integrating the Illinois utilities in their respective RTO choices.

My next set of remarks are in regard to

resource adequacy. We strongly support the Standard Market Design components of FERC's plan, particularly given that FERC's proposal to implement bid-cap of a thousand dollars per megawatthour and potentially mitigate real-time prices during system constraints, capacity payments to those generators become a critical aspect of ensuring that generation owners have the opportunity to recover their fixed cost and sustain their investments.

While generally supporting FERC's resource adequacy proposal, EME believes that several specific aspects of the proposal must be changed in order for it to achieve its purposes.

First, the FERC believes that bilateral power supply contracts need not be unit specific but should be allowed to rely on a system portfolio of physical resources.

EME also believes that in order to satisfy FERC's resource adequacy requirements all existing and future bilateral power supply contracts that rely on system resources should be certified that these resources are physical

EME also believes that the transmission provider, or RTO, should run a centralized capacity auction. The auction will be used to procure capacity for the deficient Load-Service Entities that fail to meet their resource obligation in the bilateral market.

For states with retail choice, including Illinois, the capacity auction will allow retail suppliers to reconfigure their offers to buy and sell in shorter-term markets. A auction will facilitate retail switching and resource deratings.

Second, FERC's proposed penalties for Load-Serving Entities not in noncompliance with the long-term resource requirement are unrealistically low and bear no relationship to the Load-Serving Entities' avoided cost of compliance. Applying penalty only if an emergency condition occurs and reliability is already compromised will encourage free riders rather than ensuring adequate supply.

In addition, FERC's proposal to further curtail in real-time the Load-Serving Entities that are short could not be carried out in a retail choice environment given that multiple Load-Serving Entities can be on the same circuit is the same point that Mr. Naumann made this morning as well.

Inadequate penalties will not achieve the objectives of inducing the Load-Service Entities to make the necessary long-term supply arrangements for the simple reason it will be far cheaper to pay the penalties than to make long-term commitments for the necessary resources.

Third, FERC has not established how the other resource adequacy requirements will be implemented in states with retail competition programs because load in these states can jump back and forth between utility retail service provider, uncertainty is created with respect to the supply and cost responsibilities of all the Load-Serving Entities.

To ensure adequate generation supplies, Edison Mission supports FERC's proposal that resource adequacy requirements be applied to all Load-Serving Entities.

My last set of commitments are related to transmission pricing and congestion management. EMC supports the aspect of the SMD proposal to eliminate rate-pancaking between ITPs, which will increase the size and reach of competitive markets for generation to the substantial benefit of both suppliers and purchasers or energy. This is especially important for the State of Illinois which will be split into two RTOs.

Elimination of rate-pancaking between PJM and Midwest ISO is critical in assuring generation located in the northern or southern part of the state can economically access the load in the other part of the state without being assessed multiple transmission charges.

Resolution of the inter-RTO rates between PJM and Midwest ISO is fundamental to establishing an efficient energy market within the State of Illinois; otherwise, it would be more economic for generation in the northern part of the state than it will be located in PJM to serve load within Ohio and Pennsylvania than to serve load within the southern part of the state that would be located within the Midwest ISO.

EME urges the Commission to fully

participate in the FERC-initiated investigation and settlement conference, pursuant to Section 206 of the Federal Power Act, with respect to the rates for through-and-out service under Midwest ISO and PJM tariffs.

This ongoing proceeding is far more important to all the electric customers within the State of Illinois than a FERC Standard Market Design Notice of Proposed Rulemaking, especially given the expedited nature of the proceeding -- this is suppose to be determined by FERC by the end of February of 2003 -- as compared to FERC's repeated postponement of the implementation deadline of the Standard Market Design.

We support the concept of Locational Marginal Pricing, LPM, which is a central element of the eastern ISO markets on which the SMP is a model.

EME has expensive experience with LMP as a participant in the PMJ market through the ownership of the Homer City, Pennsylvania, Generation Station.

EME is pleased that FERC has mandated use of LPM, given that experience has demonstrated that it is the nation's most robust and reliable congestion management system. This is inappropriate because it respects the physical limitations of both generation and transmission assets.

EME also supports the Standard Market Design Proposal that transmission access rights be financial in nature, but not physical, and that Congestion Review Rights be used to ensure fair and efficient use of the grid and to allow hedging of congestion cost risk.

In conclusion, I would like to reiterate that first, and foremost, Edison Mission Energy and Midwest Generation urge the Illinois Commerce Commission to remain focused on the critical task of integrating the Illinois utilities in their respective RTO choices.

It is imperative that the Illinois utilities participate in these markets and it is imperative that the ICC not allow the FERC Standard Market Design initiative in any way to hinder or delay the ongoing efforts of both PJM and Midwest ISO.

Thank you again for the opportunity to

participate in today's meeting. I'll be available for questions.

COMMISSIONER HARVILL: Thank you.

Next we'll hear from Constellation NewEnergy.

PRESENTATION

BY

MS. HEXTELL:

That's me. Thank you for an inviting me to participate today. It is a pleasure to share with my colleagues and hear so many details about how to make the FERC NOPR work for Illinois.

Let me just give a little background about Constellation NewEnergy. NewEnergy has been one of the retail electric supplier in Illinois since the market opened and NewEnergy has also been active in virtually every other deregulated marketplace in the United States since 1995, so we have offices in California, Texas, Ohio, Philadelphia, Boston, which it serves all the New England states, and New York, and New Jersey. I think that's it, and we recently acquired Constellation Energy Group, which is a company that owns a wholesale trading group that trades typically about 12,000 megawatts of generation. They own generation plants, including nuclear, and they also own Baltimore Gas and Electric, which is the oldest public utility in the United States. We're very proud of that.

So Constellation has a very evolved consideration of what the impact of FERC will be on the electric market because they represent generators, wholesale marketers, retail marketers, and utilities, and I have prepared some comments, which are available outside, but I think what probably if I were sitting in your seats, what I would be interested in hearing about is what's the impact of the FERC on retail competition in the Illinois, and you have surely heard from other people this morning about different tiny little aspects, but I think if you step back, there really are three words or three focuses of what -- how the NOPR can benefit Illinois.

Constellation NewEnergy strongly supports the NOPR. There's certain things that need to be tweaked and they're really kind of detailed, but when we talked to our customers, I'm sure, with the exception of the new chairman -- the Commissioners have heard sort of repeated messages that we have: What's important for the retail marketplace to succeed is transparency, regulatory certainty, and some level of flexibility that allows the wholesale market and retail market to interplay?

Allowing the NOPR to proceed and create a Standard Market Design across the utility service territories of the United States will enable some of that knowledge to become reality because what you have is a level of regulatory certainty that, as Reem was describing, Illinois is a perfect example of what we don't have.

We have half of the state that is choosing to participate in one retail transmission organization and another half of the state that's choosing to participate in another one, and what you will have as a result is it's cheaper to move power from Chicago to Ohio than it is from Chicago to Decatur, let's say. That doesn't seem to make a lot of intuitive sense, and I'm sure we'll hear some more from other people about that.

Just focusing on retail customers, what they want to do is understand where do I get the cheapest power? Why can't I buy power? Why can't I buy power from plants in Chicago to serve me in Decatur and vice versa?

What the NOPR will do is eliminate all those problems that are very complicated to explain. It will say, okay, we are going to set up this market, which everyone is going to operate in materially the same way.

As a result of that, what I think we'll see, what we have seen in other parts of our company that operate in areas of the country that have RTOs like in California, and in PJM, and in NEPO, and ISO, is that you create a set of rules where not one local distribution company has the ability to overinput.

So you have things like transparency and wholesale trading and it's easier to go on out and find how much does a megawatt of electricity cost and consistently and get an answer that's pretty similar.

That's difficult to do right now in

Illinois, because wholesale trading is limited. There are a limited number of parties and it depends on who you ask. The answer will be different sometimes from hour to hour and usually from day to day.

So creating one set of rules will allow customers to understand what are they purchasing, and where -- what's the best way to get it, and what's fair in the marketplace.

It sort of opens up -- I remember Mario did a presentation last year, Mario Porcus (phonetic) from our office, held up a black box and then he talked about this is what regional transmission organizations are for a lot of people who are deeply involved in it.

To a certain extent, supporting NOPR and the idea of creating one set of rules and one Standard Market Design will eliminate a lot of the mystery around the black box, because you'll have one set of rules that basically everyone has to play by.

The resulting impact on the way that people trade power, and the way that the trades are reported, and how transparent, that data will be reported every day. There's hourly pricing as this is in PJM.

For example, that will allow customers to make decisions about how to select that power and will also provide incentive presumably for generators to go where power is necessary and build their plants there.

So that's -- let's see, transparency, certainty, regulatory certainty, that's the other thing. Coming up with rules at the FERC level, that eliminates some of the barriers what -- you know, it's interesting when you hear electrical engineers talking about what the electric network is in the United States. It's this enormous motor.

Basically being a history major, I can't go to further into understanding that, but it's true that the physical characteristics of the network in this country are such that you theoretically could make power move across, then the rules that each state creates shouldn't have an impact on that or should have a nominal impact of that.

Truly what we want is an open market in electricity. The NOPR will get us there because it will take some of the -- this is my state and I'm protecting it away from that process, so that's the regulatory certainty.

I think that's my three points: Transparency, certainty, and what was the other one?

(Laughter.)

That's it. So thank you for the chance to come and I'll look forward to hearing your questions later.

CHAIRMAN HARVILL: Thank you. We are going to go onto Mr. Stagliano of Calpine Corporation.

PRESENTATION

BY

MR. STAGLIANO:

Thank you, sir. I appreciate the opportunity to be here. I represent the largest merchant generator in an industry that has seen a deep crisis. You may, in fact, not survive our current turmoil, which is due both to gain emphasis on behavior and regulation under which we operate.

It is interesting to me that for the third time in six years that the FERC has found it necessary to issue an order to address what is the structural problem that is at the core of the industry disease and that problem is in antidiscriminatory noncompetitive behavior on the part of transmission owners. That is the core legal issue that has sparked Order 888, Order 2000, and this proposed SMD.

It is equally true that the transmission owners who behave in the way that is required to redress with three separate orders are also overwhelmingly vertically-integrated utilities.

It is clear from the experience in the United States, and elsewhere, and from the analytical results that have been accumulating over the last 10 years that unless there is a level playing field, an access to a transmission grid, it is not possible to construct a competitive wholesale generating sector.

The fact of the matter is that transmission access and nondiscriminatory transmission access is not a discriminatory power on the part of the FERC. It is a right within the law, and although I am not a lawyer, I can tell you that I know that there is a right in the law, because I wrote that law and spent four years defending it, and the fact of that matter is that it is still impossible to believe that ten years after that law was written as a statute we have large sections of the country that still operate under one monopoly franchises. We are back to the Artaio (phonetic) decision where monopolists can still behave like a monopolist, even though there have been laws and regulations passed in order to break that power.

To me and to my company, it cannot be constructed at wholesale market for generation and for power until and unless vertically-integrated utilities cease control over their transmission access and over their dispatch powers to an independent third party. It's only through that break of function that we will be able to construct the wholesale generating sector that we wish to have.

I would say further that without that wholesale generating sector it's not possible to construct a retail competitive sector, at least not as far as most of the analytical concensus that I know of is required, so whatever one may think about the

Standard Market Design proposed rule, which is lengthy, and verbose, and probably overreaching, the fact of the matter remains that its aim is to rectify a condition that's eluded the FERC for at least six years, and probably ten.

How that happens for the moment is a matter of conjecture. We have the country divided in regions that have experimented with a form of Standard Market Design, although that still remains a work in progress, the PJM market is still different than the New York ISO market. It's still different than New York ISO market and all markets are different than the California market, and so whether or not we are going to be able to achieve some uniformity in terms of who manages the grids and who administers the market remains still an elusive goal both for the FERC and for the states.

As a company whose entire financial and business risk is born by shareholders and has no connection to ratepayers, I can tell you that we would rather not have seen the apparent battle over jurisdiction that's emerged between the FERC and the states as a result of the issuance of this order.

That battle bears no good for most of us small market players, and it is with the greatest fervent hope that I would urge the Commission, who I think already has acted in the best interest of public policy, not to engage in that war that seems to have separated those who believe that we are headed toward a competitive regime for the electric sector and those who believe that we must somehow return to less centuries cost of service regulation.

In my old age I did not believe that I would hear a preference on the part of otherwise responsible and respectable state regulators that you should give preference for a return to cost-of-service regulation, and even in states that have preferred to retain their monopoly approach that they seem to be satisfied with, even in those states, that right of access to the transmission grid is undeniable and they also will have to abide by that law in one form or another.

So it is with some gravity that I hope that the Illinois Commerce Commission, which has always led in this issue, will be a voice for enlightment on this issue.

I think that the FERC has proven itself capable of being adaptable to being charitable in implementing what it aims to do. The orders recently issued in regard to the Southeast Trans ISO that West Connect ISO, and RTO West all indicate a willingness and an ability to be very flexible in what principles within the SMD ought to be applied and adopted to local regions. That is both good and bad because it could be either the FERC is reacting merely to the political fire under which it is operating for the moment rather than seeking the best public policy available to it; nevertheless, regional differences are going to continue to exist and they need to be brought into the equation and the only way they can be brought into the equation s in a wise and reasonable way is to the engagement of the state commission.

COMMISSIONER HARVILL: Thank you.

Next we'll hear from Patty Harrell of Reliant Energy.

PRESENTATION

BY

MS. HARRELL:

Good afternoon. My name is Patty Harrell and I'm with Reliant Energy, and it is really my pleasure to participate in the dialogue of the proposed rule-making that FERC has issue.

For those of you who are not familiar with Reliant Energy, I just want to give you a brief bit of background exactly who we are. Of this month, October 2002, Reliant is a newly-formed Houston-based company. You say, why do you say newly-formed? I've heard that name before. Well, Reliant has just recently separated into two brand new companies. One of the new companies is known as CenterPoint, and CenterPoint consist of all the generation we formerly held in Texas, as well as both gas and electric transmission and distribution utilities across the country.

The new -- the other new company, which retained the name Reliant Energy, which is whom I represent today, consist of 21,000 megawatts of generation across the country of which about 1275 megawatts are right here in Illinois.

In addition, we also have 3500 megawatts in Europe and first option to purchase the 14,000 megawatts that are currently owned by CenterPoint in Texas, so that's a quick summary about Reliant Energy.

With respect to the topic at hand today, we filed a substantial binder full of information. This is what it looks like, for those of you have who even seen it, and this contains our thoughts on a variety of a topics addressed in this proposed rule-making. Because of the size, we did not bring 75 copies with us today, but we would be happy to provide a copy to anybody who would like to see this up close and personal. That's not a problem. Just let us know. Because of the size of the binder, let me also tell you a little bit about its construction, how it came together.

Prior to the issuance of the NOPR, we developed a variety of policy positions, if you will, on different topics that are addressed in the NOPR, so we prepared a White Paper or each topic, we prepared a question-and-answer matrix, as well as a one-page summary, and you'll find all three of those documents behind each tab in this binder.

In addition to that, subsequent to the NOPR, it really behooves us to go back and compare our policy position with what was in the NOPR, so there's a fourth item in there that is the result of our comparing and contrast exercise with our position and what's in the NOPR.

Again, I don't want to walk through the binder today, because it is a bit voluminous, so I want to give you an extremely high level of review of what you will find in a very condensed fashion here.

First of all, FERC said something to provide a number of positive steps that would provide much needed certainty and stability for all market participants. This objective is on target with exactly what is needed in this industry at this point in time.

While the NOPR is a major move in the right direction, it's admittedly not yet perfect so Reliant Energy is committed to agressively work with all parties to make it better.

From the perspective of Reliant Energy, there are three things that stand out as being the most important in the SMD.

The first topic is resource adequacy. We believe that the FERC is right on the mark in requiring that resource adquacy be addresed in a sufficiently core fashion; however, FERC relies heavily on penalties as incentive mechanisms take part, encouraging the as buyers of the market to procure adequate capacity. This is a point where improvement is needed because penalities won't keep the lights on as well as steel in the ground.

The second issue that jumps out at us in the SMD relates to price and mitigation. California has taught us a lesson that you should not rely on after the fact mechanisms for mitigating market prices. It's absolutely critical that markets have price certainty, once the market has been run, it's too late to unwind all the sales from all the purchases; therefore, any market price mitigation needs to be applied.

One improvement needed in the FERC SMD is to make use of an automated mitigation procedure not just an option but make it a requirement and anyone who passes the automated mitigation procedure test is assured that the price awarded in that market will not be secondguess one year, two years or some point down the road in the future.

The third issue, and the last issue that I'll address immediately here that jumps out at us in the MSD relate to market monitoring. FERC's MSD did not specify the details exactly how the market will be monitored. The market needs to not only monitor for supplier behavior but also behavior of buyers and, equally important, the behavior of the operator of the market, the ITP.

In addition, measurements of market performance by the market monitor need to be based on realistic price expectation.

At this point, I want to conclude my high level overview of the voluminous binder and I would look forward to any of your questions.

COMMISSIONER HARVILL: Thank you. Thank you. I appreciate your comments here today.

Finally, our late addition to the panel we have Jacob Williams from Peabody Energy.

PRESENTATION

BY

MR. WILLIAMS:

Thank you very much for making an accommodation for us to address the group here.

For those of you who don't know, Peabody Energy is the world's largest coal company in the U.S. electric market. Ninety-nine percent of all the electricity in the United States is derived from coal that Peabody mines. We have a rather large stake in the electricity market in the U.S.

I think of it it another way, all the utilities in the State of Illinois and many of the other generating companies here represented all buy coal from Peabody in some form or fashion. Coal supplies over 50 percent of all the electricity in the United States and is the reason we have low cost electricity in the United States.

Peabody's interest in standard market is design --

COMMISSIONER HURLEY: What did you just say?

MR. WILLIAMS: Coal supplies over 50 percent of all the electricity in the United States. That is the reason we have low cost electricty in the United States. I would be happy to give you the documents to support that, but it's a very clear relationship.

COMMISSIONER HURLEY: How long are they?

MR. WILLIAMS: I have one slide that I'll show you afterwards that's a very clear relationship.

COMMISSIONER HURLEY: I'm just trying to add a little levity. I see eyes closing. I'm jealous because I can't do it.

MR. WILLIAMS: Peabody's interest is a few-fold. First of all, we are developing two 1500 megawatt -- a mouthful -- projects in the middle part of the country, one right in the State of Illinois 40 miles southeast of St. Louis in the heart of the Southern Illinois coal field. The project's name is the Prairie State Generation.

The second is a project in western Kentucky, appropriately named the Thoroughbred

Generating Station, similar size project, again in the coal fields. Both of these represent both a very low cost resource going forward and also employing about 455 people long-term and construction averaging 1500 construction jobs over a four-year period, a major economic impact both in the development and in the construction, as well as the operation.

Think about it another way, they are the two largest green field coal plants built in the United States in the last 20 years. Think about it. We have lived off excess coal and nuclear and transmission for the last 20 years and essentially haven't built a baseload, now all of a sudden we're starting to deal with the issue of building major transmission and building baseload facilities that require major transmission, so these market rules that are coming into place are coming into place in a very interesting time in the energy industry. Just our project alone in Illinois will have over $3 billion economic impact in the State of Illinois, not a trivial project to the state.

In order to develop these kinds of major capital infrastructure projects and provide low cost electricity, you need transmission to make it happen. You have to have transmission to get that built in some form or fashion. FERC's SMD is a step in the right direction in terms of making a marketplace that will allow some baseload very capital-incentive, very long lead time projects that actually get built without the uncertainty in the marketplace would just kill a project like we are talking about.

FERC's goal is to develop a vibrant wholesale market which will provide both reliable and, more importantly, low cost electricity to the customers, not only reliable low cost, and its goal is also to make sure, to the best extent, possible mitigate market power and to allow a diverse fuel supply to continue to meet the generation going forward.

If we don't do that, we could be in a situation where we can only put gas units near load because transmission can't get built, because they can't get financed, so that's the way we have headed over the last 15 years.

We also need to expand our underinvested transmission system. We have not expanded the transmission system in 20 years in the United States in any meaningful way. FERC is trying to treat two noble goals. And while it's in great detail, the SMD, you can get into all the minutia and everyone's been through that. We clearly support it.

There are a few issues out there that need to be addressed though. First is how do you incent the expansion of transmission system when it is going to reduce market prices to customers? How do you insnet the transmission providers to do that? It's a tough problem today, because they aren't necessarily incented.

In fact, if you are a generation owner and you expand your transmission system in that area, you may be lowering the market price for power for your generators, which reduces your stock value if you are on the MAPP, so there's a bit of a concern there.

The added dilemma is that -- that when you build a major transmission line to reduce the LMP differential between two places, once you put that facility in place, the capacity revenue right value goes down to the minute you put that facility in place you have got no revenue to capture the value you just created by lowering market prices on the other end. That's a part of SMD that does not solve that piece.

What SMD does do, which is very noble, is it says through LMP pricing, you'll see parts differential between Point A and Point B. You know what the volume is of solving that problem will be. Now how do I invest and capture the value of that or at least pass it on to customers? It's hard to do because I can't buy those future values going forward. I only know there's a price differential today and it may have existed for many years, but I can't actually capture it. That's an area that people leave FERC in probably to the extent -- actually legislation is going to be required to start what many have called a National Energy Bottleneck. We are not sure SMD actually solved that problem. It only gets us a step in the right direction.

And, finally, you think about it. We

have got projects that are $2 billion kind of projects. We are putting a hundred million in one project and 200 million in another project into the transmission system in that area. Just to get not only our project tied in, but essentially solve the National Energy Bottlenecks that have been there for 20 years.

It's hard for us to capture the value we create by lowering prices to customers on the other end of the line. It's very different than any gas unit where a gas unit -- your gas unit peaking load, but you are not there hour by hour lowering prices. A baseload coal plant is a very different animal and it has a very different impact on the system.

And, finally, you think about the timing, and this is the other concern we have. You're talking about a project that takes five and six years to build and we generally need to build baseload plant in the U.S. for the first time in 20 years. If it takes us two or three years to resolve how this transmission market's going to work so that then we can go ahead and start building power plants, we are eight years down the road before some of the major baseload plants can't get built.

Think of it another way. If we are working with customers, they may be only as far as 200 miles away from the plant, but they can't get a firm right to get power out of this major capital-incentive plant. How are they going to be able to commit to it?

We need to move this along -- this process along so that, in fact, there's some security, some certainty as to how the transmission system operates. Their rights are out, and they can procure themselves. In fact, they can get access to the new baseload unit that will be needed in this country.

So with that, I thank you and will be open to any questions.

COMMISSIONER HARVILL: Thank you.

Are there questions?

COMMISSIONER HURLEY: Well, let me make a compelling argument, Mr. Jacob, but let me ask you this. Why should I, as a state commission who is responsible for sending a message to the FERC, why should I care about what you are arguing?

MR. WILLIAMS: Well, two-fold, and I'm going to pick the State of Illinois, since that's where we are at, and I'll also --

COMMISSIONER HURLEY: That's what I'm suppose to care about, so I'm told.

MR. WILLIAMS: Well, first of all, the baseload resources are the things that are going to insulate the state from volatility and fuel prices on natural gas -- if the natural gas prices goes up, and we have gone further and further into natural gas flow, we have no insulation from that, unless some more baseload resource. It's a way of protecting the consumers if the State of Illinois from price volatility to other fuels.

Secondly -- and this is the bigger picture -- for the State of Illinois, the State of Illinois has a great economic incentive to use the energy resources it has at its fingertips, even if it means exporting some of that to other states, because the job creation, the tax base and all of that to go into those communities can be a very large sum, a very great impact into the communities and transmission doesn't stop at the state boarders. And by creating this market, you can move the coal that is mined in and then is turned into electricity in this state. You can move it into other states to the benefit of the State of Illinois and its taxpayers who, in my mind, are also its customers.

COMMISSIONER HURLEY: Its taxpayers say that's a reason.

MR. WILLIAMS: In many respects, the customer of the State of Illinois are also its taxpayers. And when you see -- when you get economic benefits that may reduce taxes because of the tax base created and jobs created, that is good for the State of Illinois.

COMMISSIONER HURLEY: Okay.

MR. WILLIAMS: And, therefore, and I realize that a state commission has trouble sometimes because you are charged with looking at an electric rate not necessarily with the full economic picture of the State of Illinois, which is a different issue.

COMMISSIONER HURLEY: Well, I would like to think that we take things a little further than that. Some would you argue we are rather narrow-minded. Thank you, Jacob.

So glad to see Vito. While the last year, year-and-a-half you have been in California, you have not lost any of your fervor of your beliefs.

MR. STAGLIANO: Thank you. It's difficult to lose fervor at my age.

COMMISSIONER HURLEY: I was thinking of myself. It would be sort of interesting. When did you leave the FERC?

MR. STAGLIANO: In 1993.

COMMISSIONER HURLEY: 1993? So it's been about eight years since you have been gone. It's been interesting. I came back to the Commission after being here about eight or nine years afterwards and I said to the people that I was the sitting up here what have you people been doing while I've been gone. I'll bet you go back and say exactly the same thing.

MR. STAGLIANO: Well, I try to clear my distain, but it's hard.

COMMISSIONER HURLEY: You certainly didn't today.

MR. STAGLIANO: I must say that even by looking back at the golden years when I was there, it is still --

COMMISSIONER HURLEY: That's how I felt, too.

MR. STAGLIANO: -- it is difficult not to sympathize with the current political environment under which the FERC is operating. I believe that they underestimated the reaction that they did receive once the order was issued and I must say that I was surprised, too, by the reactions, especially here in the Pacific Northwest and Southeast.

I thought that the reactions were overreactions and some of them actually came from those before they read the order itself. There was some preconceptions about it, but I don't think that it's good for the country. It's not good for public policy. It's not good for consumers to have this battle underway currently, and I hope there is a way for states, maybe through NARUC and the FERC, to start talking to one another, you know, on a more calm and determined basis than they have been able to do so far.

COMMISSIONER HURLEY: Thanks. That's all I have for now, Terry.

COMMISSIONER HARVILL: Other questions?

(No response.)

Vito, and I agree with Ed's comments to you. It's nice to see you back here in Illinois. That being said, your comments kind of outline what in your opinion would be necessary for this market to work, and I don't disagree with you there.

Given FERC Order 88, and 2000, and the most recent proposed rule-making, in your opinion is this going to be adequate to solve some of the problems that you have addressed? Does it go far enough? Does it go fast enough or is it just another fatal attempt to approach the problem that needs to be solved.

MR. STAGLIANO: Well, as you -- as you know, it's always been difficult for the FERC to enforce the decisions that it issues. It is not a very good policeman of its own policies. It is changing in someway within the SMD proposal in the sense that it assumes a far more direct role as a market monitoring in Washington, which I testified, and I think that the

FERC is both staffing up in areas where it had no expertise before and is perfectly willing to be interventionists in monitoring the markets.

That being said, it would be a tendency to go over in the extreme in the other direction and that is to stifle competition rather than merely making sure that the rules are obeyed and behavior is right on the part of everyone concerned, but the length of time that we are now facing between the implementation of Order 2000, and I don't know where that is, maybe suspended in animation somewhere, and new calendar from SMD, which will probably run for another five years.

In fact, there are ISO proposals in front of the FERC that want transition as long as 12 years. In 12 years we'll all dead, so it doesn't matter what we're, you know, going to decide today. Our national policy, or at least some of us, it's animation it is not rational to me to plan a policy implementation on a major restructuring of an industry that's being restructured for the last 10 years. That will take another 10 years to complete. That is not a reasonable proposal to put in front of people.

So the most effective counterforce to this sort of loosely-defined transition period would, in fact, be the states. The states can intervene and say, you know, the proposal from RTO so and so is -- does not need to take 10 years. They do not need to reinvent all of the software that's been operating in other places. They do not need to reinvent governance, and MMUs, and stakeholder processes. They can borrow from tested elements and get underway sooner rather than later.

COMMISSIONER HARVILL: I think it was said all the great forces will come to your aid.

Do you think there are people out there that will come to the FERC's aid in supporting their bold actions?

I spent one morning in Washington, D.C. where they cited the Endangered Species Act. If anybody can actually tell me how the endangered species act impacts the FERC's MRD proposal, I would be happy to sit down to make that link, but it's almost as if they were bold and now great forces are actually coming to prevent what they're attempting to do, and I guess the question is how do we overcome that?

Is it the regional differences that some have suggested that we must put in place asa phased-in approach? What is the most appropriate way to get this thing done, given the resistance that we have seen?

MR. STAGLIANO: The reasons for the objections appear to be disappearing, that is in RTO west. The proposal there was not really consistent with the standard market design. It was a proposal that was accepted and blessed by the regional political authorities that subscribe to it, so now they have got exactly what they wanted. I mean, the FERC gave them the whole order with very few changes and those of us who went out of our way to object to the fact that it was not consistent with the Standard Market Design were left rather speechless by the results, so it is interesting to me to see what will the regulatory authorities of the Pacific Northwest now base their objections on. They received exactly what they filed and the FERC said go ahead.

We agree that there are regional differences that your system is different than everybody else. Your electrons are blue, in the East they're red, and so we defer to the blue electrons of the West.

(Laughter.)

In the Southeast the same thing has happened. The Southeast trans order the FERC simply blessed what was filed. Is it consistent with SMD? I don't think so, but they also got what they want. So what is the objection at this point?

My sense is that the FERC is deflecting the opposition by for the moment going along with the proposal as they come before it.

COMMISSIONER HARVILL: Questions?

COMMISSIONER KRETSCHMER: Mr. Stagliano, I'm agreeing that there are regional differences, and FERC that. To pass by the governors, I would suggest does not mean that they have agreed with the changes that they want. Agreeing with the position -- the proposition that there are regional differences would not make changes in what they're asking is not really agreeing at all. It's a good PR campaign. If I were governor, I won't be fooled for two minutes by it.

MR. STAGLIANO: Well, The FERC did. Well, there is a timing and a sequencing problem here. The order -- the orders that were issued in the past two weeks for three new ISOs are out of sequence with the final order for SMD.

My assumption is that the cumulative effect of this fresh set of ISO orders, plus the reactions from the regulatory authorities that are interested in that fact, will affect the structure and the scope of final SMD rule. I have to assume that it does, otherwise, the inconsistencies will be too great to rationalize, so to the -- in the West the problems seem to be much more visceral, much more emotional, it seems to me at this point, than they are substantively because they have won on substance of it, at least until the final SMD order is issued, which will not be until late next year.

The other things that the FERC said in

this order is that they would not revisit this order in light of the subsequent SMD order. That's as good a guarantee of regulatory certainty as anybody's likely to get.

COMMISSIONER KRETSCHMER: It may be certainty, but will it be acceptable to the states?

COMMISSIONER HARVILL: Other questions? Anything from our audience? Clarifying questions? Comments?

(No response.)

If there are none, thank you all for your participation here today. It's going to be extremely valuable when we come to preparing our comments to the FERC or if the panelists for the next session are available, I would suggest we start a little bit earlier. I would think they are, so why don't we do this. Why don't we take about 10 minutes, come back in about 10 minutes to 3 o'clock and we'll begin at that time. 10 to 3 is the time we'll begin.

We are off the record.

(Off the record.)

Go back on the record.

Our last panel today is from our consumers' group. We have two representatives.

Jim Dauphinals. Did I pronounce that right?

MR. DAUPHINAIS: Yes, Mr. Harvill.

COMMISSIONER HARVILL: And on behalf of the Illinois industrial Industrial Energy Consumers, and Ron Earl, General Manager and CEO of Illinois Municipal Electric Agency.

With that being said, I'm going to turn things over to Jim to begin things and we'll wrap up with Ron.

PRESENTATION

BY

MR. DAUPHINAIS:

Good afternoon. I would like to thank the Commission for providing IIEC the opportunity to share its perspective on FERC's SMD NOPR this afternoon.

IIEC is looking to the SMD NOPR to provide for a truly competitive wholesale power market. The development of such a market is fundamental to providing a foundation for a truly competitive retail market in Illinois.

The SMD is not a revolutionary step as the product of an evolution began the Public Utility Regulatory Policy Act and the Energy Policy Act of 1992, is also decedent Order No. 88 and 2000; moreover, PJM has already implemented core portions of the SMD and MISO who's been working on these very same core portions in response to its 1998 order with FERC, so this is not the new issue. This is something that was going to happen, at least in the Midwest, even prior to the SMD NOPR.

IIEC has long supported the strong mandatory approach the FERC is finally taking in the proposed SMD NOPR. The aftermath of Order No. 2000 demonstrated that the voluntary approach to solving the problem, at least utilities making choices that may not necessarily be in the interest of their customers.

While IIEC conceptually supports the NOPR, it does not necessarily agree with all of its details, nor does it believe it is the cure all to all the problems that plague the wholesale power markets.

The implementation of SMD will not remove all the seams, between MISO and PJM into the highly-interwined nature of The RTOs. The seams can only be removed from these two RTOs by implementing a simple market which must include a single dispatch for locational marginal pricing and single common market for CRRs.

Separate LPE dispatch will lead to problems as dispatch of one RTO is likely to impact the other RTO due to the interwined nature of these RTOs.

In regard to the SMD NOPR itself, we too have concerns we'd like to focus on this afternoon. These are the allocation and CRRs and the proposed resource adequacy requirement.

IIEC is concerned that retail access customers and the suppliers will not have access to the CRRs necessary to hedge their electric purchases from LMP congestion charges under the SMD.

IIEC believes consumers will be adversely affected by the LMP system unless a market value of the transmission system remains with those consumers. This could be accomplished by assigning the value of CRR's staff that would have allocated rather than CRRs themselves.   This is the Auction Revenue Rights concept or ARR concept that Mr. Naumann spoke of earlier today.

The value of these rights could be directly assigned to utilities in case of bundled service where we still have a rate freeze in effect but directly to consumers where those consumers elected for retail access. This will make both utilities and consumersn indifferent to retail access from Illinois, at least from the perspective of potential congestion charges under under the SMD.

This approach will also make small CRRs available to the market, which is fundamental in allowing utilities, retail access customers, and RESs access to the CRRs they need to hedge their transactions against LMP congestion charges. Without such access, retail competition in Illinois will wither; however, caution should be needed in using this approach to make sure that the CRR auction do not undervalue the CRRs. For if the CRR's are undervalued, it will be at the expense of the consumers.

In regard to the resource adequacy requirement, IIEC is very concerned that it will chill retail competition in Illinois.

Mr. Naumann spoke earlier today of boom-and-bust cycle in generation earlier today. This is boom-and-bust cycle has resulted from the delay time associated with new generation construction following price spikes in the power markets.

For example, with price spikes we experienced in the midwest in 1998 and the daily and hourly markets, we didn't get the generation from those price spikes until two years later.

IIEC believes that this boom-and-bust cycles can be ultimately moderated only by the establishment of a location-sensitive liquid and transparent market out to the horizon of a new generation and transmission construction.

IIEC believes the proposed resource adequacy requirement of the FERC is a noble attempt by the FERC to jump start such a market; however, as currently proposed, requirements could undermind retail competition in Illinois by placing new burdensome requirements on the RES in Illinois.

Currently RES can supply retail access customers with financially firm contracts and these contracts do not need to be acquired in an amount in terms that exceed the RES contract -- RES contracted sales, that is the sales that the RES have already contracted for.

So, for example, if an RES has sales only going out for another year into the future, they only really need to get supplies for that year. They don't need to get supplies beyond that year.

The resource adequacy requirement could require RES to acquire physically firm power supplies and in-plant reserves for possibly three years into the future even if that RES does not have sales contracts out to that horizon. This will significantly increase the cost and risk faced by RES in Illinois. This would likely drive RES from the retail market.

While IIES doesn't necessarily oppose support of the resource adequacy requirement, that requirement should not be so onerous that it drives RES in the Illinois retail market. SMD has much promise, but, the depth is always in the details.

I look forward to your questions. Thank you.

COMMISSIONER HARVILL: Thank you.

Next we'll hear from Ron Earl from the Illinois Municipal Energy Association.

PRESENTATION

BY

MR. EARL:

Good afternoon. I'm Ron Earl, General Manager and CEO of the Illinois Municipal Electric Agency. I would like to also thank you for the opportunity to express the views of consumer-owned utilities in Illinois on FERC's proposed Standard Market Design for electricity markets in the United States.

I have submitted written comments in advance of this meeting in the interest of time. I would like to use my time here to highlight our concerns. My written remarks contain additional details that I hope the Commission and staff will consider in the deliberations that follow this meeting.

Let me take a moment to tell you who we are. The Illinois Municipal Electric Agency is a non-for-profit unit of local government that was created by an act of the General Assembly in 1983. Our job is to combine the wholesale power needs of the municipally-operated electric systems of the state and provide them with economic and reliable wholesale electricity at stable prices.

We represent 40 of the states, 42 municipally-owned utilities. We currently sell power to 30 of these systems under contracts that are primarily long term extended through 2026. We were created because our members did not have access to economical sources of power.

For the past 18 years, IMEA has filled that gap. On behalf our members, we have introduced bilateral power supply contracts and we have purchased both peak and based-load generation sources to make certain our member citizens would have power when they needed and at a cost they can afford.

I'm also a member of the Executive Committee of the Transmission Access Policy Study group, referred to as TAPS. TAPS, as it is called, is an informal association of some 1,000 transmission dependent utilities in 34 states. TAPS members own generation and purchase of substantial amount of power and energy under a variety of wholesale contracts. Like IMEA, they serve their members under long-term contracts and all depends substantially on transmission-owned and controlled by others.

TAPS has been, and continues to be, very active before Congress and FERC on issues of transmission policies; therefore, both IMEA and TAPS view FERC's SMD proposal through what we would call the lens of our customers' needs.

We are generally supportive of FERC's goals for the SMD, which we see as the elimination of undue discrimination in the provision of transmission services for all purposes and to achieve a vigorous, competitive transparent short-term energy market that will benefit customers; however, some detail of the proposal will work in opposition to those stated goals.

I would like to briefly highlight those that give us particular concern. The first is the need to protect existing transmission rights, very, very critical, and it's even after the teleconference today on that, but it's a very, very critical thing is to try to make sure that we have protection against existing transmission rights.

We have a long-term load serving obligations, as I indicated, going out to 2026. To meet these obligations, we have made major investments in generation and other power purchase arrangements.

As an example, IMEA bought a share of a large 547 megawatt coal-fired plant in Kentucky in 1990. We were able to make this purchase and finance this unit, our share of it, we had to secure long-term transmission rights. Those rights are essential to the economic viability of our investment and to our continued ability to provide reliable service to our members and their customers.

The municipal system citizens are a half a million in Illinois would suffer severely if we do not receive rights under the SMD that are, in fact, equivalent to our own transmission rights that we have today.

The SMD NOPR states an intention to protect existing transmission rights. We were very troubled by that fine print, which in many places suggest that we may end up with rights that are significantly less secure, less valuable, and shorter term.

SMD proposes to use congestion revenue rights to CRRs we have been talking about today as a hedge against the costs imposed by the use of locational marginal process, but FERC's proposal to auction the CRRs is an invitation we believe to gain the system and initial allocation of CRRs under FERC's proposed methods to see us loosen even our existing firm transmission rights.

We are also concerned about the bid based, not cost based LMP scheme using the basis for assess congestion charges, which will also be subject to gainmanship. Existing rights to transmit existing generation commitments to load must be honored.

IMEA and TAPS will be urging FERC to craft its final SMD rule and the associated implementation details to fully protect these existing transmission rights.

The second point I would like to bring up is that the SMD proposal should be modified to clearly enable Load-Service Entities, such as us, to obtain new long-term transmission rights that will allow assured delivery of new resources to our load without significant risk to congestion costs.

Right now we are examining which of the number of new baseload facilities is it best for us to invest in on behalf of our members.

I think earlier today we talked about the new load here, the 8,000 megawatts, and I think some of the questions that were asked, what kind of fuel is that? Well, it's gas. What kind of units are those? Well, they're mostly intermediate, and if we don't go out -- we and others don't go out and start looking for maybe coal-fired baseload, the gas we believe is going to go down into the baseload and become a very, very high priced market in the future.

So we are, indeed, as well as many people, are need of looking for coal-fired baseload for the future or really totally on the market. This will be a purchase that could exceed hundreds of millions of dollars and will be a key component in our members' ability to serve their customers reliably and at a reasonable cost.

We have looked so far at 14 different companies. Of course, the number one thing that we have to ask can we have it delivered to our control areas in Illinois? Can they come from the south part of Illinois? To the north part? What is the transmission situation?

This is true for many public power cooperatives, as well as investor-owned systems across the country. The simple fact is that we must meet our load reliably which requires long-term investments, long-term contract commitments, and long-term planning.

Recent experiences show that we cannot rely on the merchant sector and short-term markets for needed capacity. Our members do not wish to subject their customers to that uncertainty, but if we cannot secure firm transmission rights to deliver the output from this project, we may not be able to secure the necessary financing.

I think all of us have probably seen the Wall Street Journal today, Page 82, and what's going on in the world of trying to finance through energy units in the future and that will expose or members and customers to something they don't want, the uncertainty, the volatility of the cyclical market power; unfortunately, the SMD proposal speaks in terms of securing future rights of one week, one month, one year, or perhaps longer in duration.

Again, that perhaps longer is not good enough. IMEA and other TAPS members are not speculators. We cannot build plants with 30 to 50 year lives and go out and try to issue debt as amortized over 30 years with only a short-term delivery right and have congestion and protection.

We are willing to pay for our fair share of the cost of transmission leading to integrating the resources into the network and to deliver power from those resources to our loads on a reliable basis, but we are not willing to rely on out bidding all other market participants in annual auctions for the transmission rights to secure delivery of long-term generation investments or power contracts.

In fact, we were very progressive in converting all our member loads to network integration transmission service under Order 888, open access transmission tariffs. We did so with the understanding that our transmission providers would be responsible for maintaining and building the necessary transmission capacity to meet our needs. We are fearful, and for good reason, that SMD, as proposed by FERC, will undo that contract.

We'll be urging FERC to modify its MRD proposal to clearly provide that Load-Serving Entities can designate new network resources dedicated to serving their load and can obtain new long-term transmission rights that makes a life of those resources, and we encourage the Illinois Commerce Commission to do likewise.

That leads me to my final point on participant funding of new transmission upgrades. I respectfully disagree with Mr. Naumann, who I have a high regard for, and some of the comments he made earlier.

If the objectives of SMD are to be realized, it is essentially that new transmission be built in a timely fashion. That's the whole problem here is transmission. Congestion must become the exception, not the rule.

Unfortunately, FERC's SMD proposal states a strong preference for what's called Participant Funding Mechanism for getting a new transmission built. Participant funding is an undefined, untested concept that represents a number of problems. It apparently presumes that the individual market participants will step up and pay for the construction of new lines in advance in exchange for the rights to congestion revenue, this despite long construction lead times and the changing nature of grid flows overtime.

It is important that new transmissions be built promptly. Relying on participant funding is likely to lead to significant delays for a number of reasons. Most transmission lines have multiple purposes.   If you've ever seen how power goes from A to B, you are going to be surprised the different paths that it takes if you saw a load flow model.

To get approval of new transmission line, it's often necessary to demonstrate multiple benefits and that the proposed line is the least cost solution to meeting a variety of needs, including local voltage support, reliability under various contingencies, as well as improving access to economic sources of power.

The multiple purposes is that lines would be create significant free rider problems. Parties may be encouraged to wait and see if someone else will pay for a line.

In addition, the beneficiaries of the network upgrade will change over time with changes in load, generation, and grid topographic. Efficiency and cost efficiencies will often require upgrades in size larger than is required for immediate needs of a particular market participant.   As a result, under participant funding regime, optimal improvements from a regional, long-term planning perspective may not be made.

Finally, we need to be very careful not to create new incentives to maintain congestion and oppose new construction. For a market participant funding a new line in exchange for rights to associated congestion in revenue, that market participant may very well become an opponent of the next new line. That would lessen congestion and, therefore, the value of its own congestion revenue rights.

For all these reasons, we seek to convince the FERC and the SMD proceeding not to primarily place reliance over participant funding in order to achieve a robust grid. FERC can deal with the problem with a rate design that is assigns costs to both load and generators based on costs and benefits received.

These problems also strongly suggest that we need a regional transmission planning regime that includes a clear obligation on the part of RTOs to build or cause construction of transmission necessary to ensure reliable service for customers and reasonable access to competitive regional markets. Assignment of the costs of this integration should track cost and benefit.

Let me close by saying again that we are generally supportive of a uniform market structure for the U.S. electricity market; however, the details we have outlined here are vitally important if the market is actually going to work for the benefit of the end-user consumer.

If the rates that underlie SMD can be made to work for us with our marketing experience and knowledge, then they will not work for individual customers in a retail access environment.

We hope the Commission will agree and take these matters up with FERC. Thank you again for inviting me to offer these remarks.

COMMISSIONER HARVILL: Thank you.

I'm going to turn things over to the

other Commissioners.

(No response.)

Now Commissioner Kretschmer, I know you have a comment.

COMMISSIONER KRETSCHMER: Yes. Mr. Earl, it's nice to see you again.

MR. EARL: Good to see you. It's not snowing this time.

COMMISSIONER KRETSCHMER: That's true. That's true. First of all, I share your concern on heavily dependence on natural gas. I do think we need to have a better mix of fuel, natural gas certainly with its high ups and downs, that's not going to change, and certainly there is a serious effect if we try to use peaker plants as baseload, so I agree with you.

I also share your concern about the problems that would arise if you did not have the same privilege to transmission rights that you have now. I didn't understand that.

However, having said that, how would you suggest we fund new transmissions? Certainly, the utilities that are not going to have control even thought they might have ownership, many won't have ownership, but they won't have control of their own transmission lines.

You would not expect I assume to have utilities build transmission lines in their own service territories if they have no control over their use or who's going to be using them. How else having participants fund them would you fund these?

MR. EARL: We tried to work with the transmission owners and even some of the rates of return have gone up to some pretty high double-digit numbers that transmission owners themselves would see this as a very viable market. And when you look at 12, 13, 14, 15, 16 percent rate of return, that that would be a very good market for people to get into and try to build. And one of the things we would like to encourage is that rather than going out and trying to do a participant funded approach where you are going to find it's just going to get totally bogged down in terms of is it ever going to get built as there is an incentive and a way not to build new transmission.

The last transmission you now the more

valuable whoever has transmission becomes and more valuable to the generations that are located there, so I think participant funding is not going to work. I think it's going to be a very slow process and we are going to wind up with congestion management, Locational Marginal Process, all these things issues that we talked about all day today.

COMMISSIONER KRETSCHMER: Don't you think we're going to have some problems as they start trying to raise transmission costs? I heard 30, 50 percent. I can't see that many states --

MR. EARL: No, I would not want to go that high and I hope we would not go that high. We have worked with some of the MISO transmission owners, and I don't think their numbers got that high.

COMMISSIONER KRETSCHMER: Well, I'm just reading published reports talking about a need for increase maybe 30. They all say the basis is low so the increase would not seem that big in dollars, but when you talk about 30 to 50 percent increase, that's high no matter who's doing it.

MR. EARL: It is. It's an issue, but I don't believe participant funding is the way to go. I think it's not going to succeed and we are going to be left with a transmission grid today and we are going to be left with a real mess.

Like you say, we need to try to all understand what does locational margin, processing mean, what does congestion rights mean? How do you auction them off? How about long-term commitments? How do you go out and get 30 year debt when you can only get a 5 or 10-year transmission right? It's a real mess. The solution to all this is to have more transmission lines. I mean, we all know that.

COMMISSIONER KRETSCHMER: That's the solution, the question is who pays, you know, and --

MR. EARL: We don't mind paying our share, but, I mean, to get the participants to start putting up money up front, you get into all kinds of a variety of issues that are turned out here in terms of is it going to be a successful approach.

COMMISSIONER KRETSCHMER: Well, couldn't you use the other analogy, for year after years it was claimed that the utilities padded their rate base so that they could get a higher rate of return.

Are you afraid that perhaps the transmission owner companies might pad their rate base in order to get a higher rate of return?

MR. EARL: They might. They might.

COMMISSIONER KRETSCHMER: Okay. Thank you.

COMMISSIONER HARVILL: Other questions?

(No response.)

I have one, and he's still sitting in the back. I have question for Craig. In PJM obviously you have an LMP basis. How many new transmission has been built under that system? Has it evolved to what Mr. Earl's speaking to or has new transmission been built to address the congestion? Sorry to put you on the spot.

MR. GLAZER: That's quite all right.

We have had an extensive amount of new transmission built to alleviate congestion to interconnect new generators and even interconnecting new generators can alleviate congestion if they're located in the right place. We have had considerable transmission being built.

What we need to see, quite frankly, and was emerging on the horizon is merchant transmission providers, somebody who solely gets into this business, and I think just picking up on the conversation before, I think we have to separate out reliability upgrades from economic upgrades.

Reliability upgrades need to happen, and they it needs to be -- you can't wait for somebody to come up and come up with the proposal. I'm not sure on congestion -- on clearing congestion if we ought not to allow the market to work and have some economic opportunities if, in fact, the generation's getting expensive, a merchant transmission provider will come in and say I'm going to build and I'm going to get some of these nice returns for doing it.

I don't think we should see the system quite as negative as was presented. We have seen a lot of interest in new merchant transmission.

COMMISSIONER HARVILL: As the transmission been known, has it been participant funded or it been --

MR. GLAZER: Our system basically is participant funding right now. Again, we separate out. If it's a reliability upgrade, it's rolled into rates. Everybody pays it. We don't start separating out the benefits, but if it's clear congestion, we, in fact, look to determine or if it interconnects to a new generators. We determine what was the problem. What caused this cost to be incurred, and some of you heard a lot about on the telephone I'm sure, and, as a result of that, who should pay?

So we have been doing participant funding now. Is it easy? Can you get into problems? How did you identify who's the beneficiary? Would the line have otherwise been built? They are issues, but that's why you have an independent transmission provider that doesn't have a stake in making those issues and would appeal FERC, and MISO, and PJM.

So I don't participate funding is quite as controversial as it necessarily needs to be, in fact, it worked pretty well. Reliability upgrades it gets done right away, rolled into rates, paid for. They don't wait around for participants. Economic ones do, and that's the way you want it. You don't want to start a command-and-control system to say this is the solution.

COMMISSIONER HARVILL: Thank you. I asked the questions, because I don't know, so appreciate your still being here.

Any other questions? Comments? Concerns?

(No response.)

Anything from the audience?

(No response.)

Springfield?

(No response.)

That being said --

COMMISSIONER HURLEY: I have a couple of observations.

CHAIRMAN WRIGHT: Just my complements to you and to our panelists today. For a new chairman of the Commission, this has been quite informative, provocative in certain circumstances in today's discussion, and I think instructive to the Commission to go about our business on this issue, so in your position as Chair of the Electric Policy Committee, thank you for organizing this today.

CHAIRMAN HARVILL: You are quite welcome.

COMMISSIONER HURLEY: I wanted to say the same thing. I also wanted to say to Craig it is nice that you certainly did a lot of work on the telephone side when you were on the Ohio Commission, and can we draw any comparison to you to UNE rates and recent UNE rates that are going on?

MR. GLAZER: We don't do calls at dinner time.

COMMISSIONER HURLEY: It's at least nice that some of us do draw analogies between the two industries, so oftentimes the industries have remained so separated, and, yet, the energy industry is going through so many of the same issues that we went through in the telecommunications industry, and many years ago and continued to.

I want to thank all the panelists, as well and recommend to Commissioner Harvill, while I think this was a terrific panel, I think if we do it again, we ought to split the two panels up and have a morning and afternoon session in more of a debate fashion. I think it would keep some of the people in the audience awake obviously.

COMMISSIONER HARVILL: I'll take that into consideration and, again, I thank all the panelists for participating today. It's been both educational and entertaining at times.

That being said, the Commission is in process of drafting our comments and we'll continue along that path.

It is my intention to schedule other meetings, not quite as long as this one, to educate the Commission and perhaps help us along the path to preparing these comments to the FERC.

With that, I thank everybody who participated today, everybody who sat in the audience through the meeting, and we are adjourned. Off the record.

(Whereupon, the above matter was adjourned.)